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PACIFIC RUBIALES ENERGY CORP.
MANAGEMENT DISCUSSION AND ANALYSIS

August 9, 2011
Form 51-102 F1
For the three month period ended June 30, 2011

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 29.

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 interim condensed consolidated financial statements for the second quarter of 2011, and the 2010 audited annual consolidated financial statements of the Company and related notes. The preparation of financial information is reported in United States dollars and is in accordance with International Financial Reporting Standard 1 and International Accounting Standard 34 as issued by the International Accounting Standard Board (“IASB”) unless otherwise noted. Note 24 to the interim condensed consolidated financial statements contains a detailed description of the Company’s first annual reporting under IFRS. All comparative percentages are between the quarters ended June 30, 2011 and June 30 2010, unless otherwise stated. The following financial measures: (i) EBITDA; (ii) funds flow from operations; and (iii) adjusted net earnings from operations, as referred to in this MD&A, are not prescribed by IFRS and are outlined under “Additional Financial Measures” on page 33. All references to net barrels or net production reflect only the Company’s share of production after deducting royalties and the partner’s working interest. A list of abbreviations for oil and gas terms is provided on page 31.

In order to provide shareholders of the Company with full disclosure relating to potential future capital expenditures, we have provided cost estimates for projects that, in some cases, are still in the early stages of development. These costs are preliminary estimates only. The actual amounts are expected to differ and these differences may be material. For further discussion of the significant capital expenditures, see “Capital Expenditures” on page 17.

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 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 gross production of approximately 235,000 boe/d, with working interests in 40 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 on the Company’s website at www.pacificrubiales.com. Information contained in or otherwise accessible through our website does not form a part of this MD&A and is not incorporated by reference into this MD&A.

2. Second Quarter Highlights

During the second quarter of 2011, the Company continued the trend of outstanding production growth and exploratory success, leveraging its technical know-how and operational expertise. The results for this period 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.

- **Strong financial results.** Second quarter confirmed the capacity of the Company to deliver strong financial results, reflected by a significant increase in production and improvements in realized prices. Consolidated net earnings for the second quarter of 2011 were $349.4 million, or $1.30 per common share, compared with net earnings of $14.4 million for the second quarter of 2010, or $0.05 per common share. Adjusted net earnings for the second quarter of 2011 were $266.7 million, compared to $49.9 million in the second quarter of 2010. Revenue increased 168% to $957.5 million compared to $356.8 million in the same period in 2010.

- **EBITDA doubled resulting in significant funds generation.** EBITDA for the second quarter of 2011 totaled $558.3 million, a significant increase of 181% as compared to EBITDA for the previous year's second quarter of $198.6 million. EBITDA for the second quarter of 2011 represents a 58% margin in comparison to total revenues for the period. Funds flow from operations increased to $400.2 million in the second quarter of 2011, compared to $148.4 million in the second quarter of 2010.

- **Production continues to grow.** Average gross production in the second quarter of 2011 was 221,896 boe/d, 88,092 boe/d net after royalties and field consumption, 60% higher than in the same period of 2010, and is the result of the production from more than 43 new development wells, mainly in the Rubiales and Quifa fields.

- **Continued focus on exploratory activities with a success rate of 92%**. During the second quarter, the Company drilled 13 exploratory wells and acquired 772 km of 2D seismic with a total net investment of $117.2 million.

- **Significant improvement in the operating netbacks.** Crude oil operating netback during the second quarter of 2011 was $64.32/bbl, 50% higher in comparison to the same period in 2010, due to higher realized prices. Natural gas operating netback was $27.31/boe, 70% higher in comparison to the same period of 2010, also due to higher realized prices.

- **Continued development of capital expenditure program.** Capital expenditures during the quarter ended June 30, 2011 totaled a net amount of $307.7 million (2010 - $134.7 million), of which $109 million were invested in the expansion and construction of production infrastructure; $117.2 million were invested in exploratory activities; $50 million were invested in production drilling activities; and $31.5 million were invested in other projects.

- **Environmental permits for Quifa.** In June 2011, the Ministry of the Environment of Colombia granted the required environmental permits for Quifa Southwest and Quifa North which allow the Company to continue its development drilling campaign in Quifa Southwest and to proceed with its exploration drilling campaign in Quifa North.

- **Maurel & Prom.** On May 6, 2011, the Company acquired a 49.9999% interest in Maurel and Prom Colombia B.V. ("Maurel & Prom") from Les Establissments Maurel & Prom, for cash consideration of $63.4 million and subject to certain exploratory commitments. Maurel & Prom holds interests in five exploration blocks located onshore in Colombia.

- **Standard & Poor's raised the Company's credit rating.** On July 6, 2011, Standard & Poor's Ratings Services raised its corporate credit rating on Pacific Rubiales to "BB" from "BB-". They also raised their rating on Pacific Rubiales' $450 million senior unsecured notes due 2016 to "BB". Standard & Poor's also indicated that the Company's outlook is stable.

- **Operational update in the Arauca Block.** On July 18, 2011, the Company announced an operational update for the Arauca Block, where the company drilled the TORODOI-1X exploratory well, the first of two exploratory wells planned for 2011 in the Arauca Block. This well is currently being tested.

- **Cash dividend paid to shareholders on June 30, 2011.** On June 13, 2011, the Company announced a cash dividend in the aggregate of $25 million, or $0.093 per common share. The dividend was paid on June 30, 2011 to shareholders of record as of June 17, 2011; the ex-dividend date in Canada was June 15, 2011.

3. Financial and Operating Summary

Financial Summary

A summary of the financial results for the three and six months ended June 30, 2011 follows:

	Three Months Ended June 30		Six Months Ended June 30	
(in thousands of US$ except per share amounts or as noted)	**2011**	**2010**	**2011**	**2010**
Oil and gas sales [1]	**$ 957,509**	$ 356,848	**$1,541,058**	$ 736,279
EBITDA [2]	**558,339**	198,585	**920,866**	430,551
EBITDA Margin (EBITDA/Revenues)	**58%**	56%	**60%**	58%
Per share - basic ($) [4]	**2.08**	0.76	**3.43**	1.66
Net earnings	**349,375**	14,438	**279,782**	90,565
Per share - basic ($) [4]	**1.30**	0.05	**1.04**	0.35
- diluted ($)	**1.20**	0.05	**1.00**	0.33
Adjusted Net earnings from operations [3]	**266,707**	49,910	**400,928**	148,839
Per share - basic ($) [4]	**0.99**	0.19	**1.49**	0.57
Funds Flow from Operations	**400,202**	148,382	**666,909**	297,770
Per share - basic ($) [4]	**1.49**	0.56	**2.49**	1.15

Adjusted Net Earnings from Operations

Net earnings for the second quarter of 2011 included a number of non-operating items totaling a net of $82.7 million mainly related to mark-to-market gain on derivatives, share-based compensation, and foreign exchange loss. These non-cash items may or may not materialize in future periods. The adjusted net earnings from operations follow:

	Three Months Ended June 30		Six Months Ended June 30	
(in thousands of US$ except per share amounts or as noted)	**2011**	**2010**	**2011**	**2010**
Net earnings (loss) as reported	**349,375**	14,438	**279,782**	90,565
Non-operating items [5]				
Loss (gain) on risk management contracts	**(84,896)**	(5,144)	**7,738**	(10,161)
Share-based compensation	**705**	31,853	**47,392**	72,675
Equity tax	**-**	522	**68,446**	1,044
Foreign exchange (gain) loss	**1,523**	8,241	**(2,430)**	(5,284)
Total non-operating items	**$ (82,668)**	$ 35,472	**$ 121,146**	$ 58,274
Adjusted earnings from operations [3]	**$ 266,707**	$ 49,910	**$ 400,928**	$ 148,839

1) *See additional details explained in the "Commercial Activity" Section on page 13.*
2) *See Section 10 – "Discussion of 2011 Second Quarter Financial Results – EBITDA" on page 20 and "Additional Financial Measures" on page 28.*
3) *Adjusted earnings from operations is a non-IFRS financial measure that represents net earnings adjusted for certain items of a non-operational nature including non-cash items. The Company evaluates its performance based on adjusted net earnings from operations. The reconciliation "Adjusted Net Earnings from Operations", lists the effects of certain non-operational items that are included in the Company´s financial results. Adjusted net earnings from operations may not be comparable to similar measures presented by other companies. See "Additional Financial Measures" on page 28.*
4) *The basic weighted average number of common shares outstanding for the second quarter ended June 30, 2011 and 2010 was 268,717,010 (fully diluted – 298,832,627) and 263,009,942 (fully diluted – 276,177,629), respectively.*
5) *See additional details explained in Section 10 – Discussion of 2011 Section Quarter Financial Results" on page 18.*

Operating Summary

The Company produces and sells crude oil and natural gas. It also purchases crude oil from third parties as diluents and for trading purposes. The following sets out the netback for the second quarter of 2011 as well as a comparison of the combined total for the second quarter of 2010:

Operating Netback Crude Oil and Gas

Combined crude oil and gas operating netback improved during the second quarter of 2011 was $60.66/boe which was higher by 56% as compared to the same period of 2010. Crude oil operating netback during the second quarter of 2011 was $64.32/bbl, 50% higher in comparison to the same period in 2010, due to higher realized prices and lower differentials with respect to WTI. Natural gas operating netback was $27.31/boe, 70% higher in comparison to the same period of 2010:

	Three months ended June 30,			
	2011	**2011**	**2011**	**2010**
	Oil	**Gas**	**Combined**	**Combined**
Average net production (after royalties and field consumption)(1)	**77,259**	**10,833**	**88,092**	**55,102**
Average daily production sold (boe/day)(1)	**98,265**	**10,723**	**108,988**	**64,329**
Operating netback ($/boe) (2)				
Crude oil and natural gas sales price	103.60	31.85	96.54	60.96
Cost of production (3)	5.45	2.65	5.18	4.75
Transportation (trucking and pipeline) (4)	9.74	0.56	8.84	6.01
Diluent cost (5)	16.33	-	14.73	10.26
Other costs (6)	6.26	1.98	5.84	1.25
Overlift/Underlift (7)	1.50	(0.65)	1.29	0.18
Operating netback ($/boe)	**64.32**	**27.31**	**60.66**	**38.51**

(1) *See additional comments on page 12 – "Reconciliation of Barrels Produced and Purchased vs. Barrels Sold".*
(2) *Combined operating netback data based on weighted average daily production sold which includes diluents necessary for the upgrading of the Rubiales blend.*
(3) *Cost of production mainly includes lifting costs and other production costs such as personnel, energy, security, insurance and others.*
(4) *Includes the transport costs of crude oil and gas through pipelines and tank trucks incurred by the Company to take the products to the delivery points to customers. The increase over the prior period of 2010 is mainly due to the higher volume of crude oil transported via tank truck due to increased production, coupled with an increase in the overall land transport costs in Colombia during 2011.*
(5) *Net blending cost is estimated at $3.0 per bbl of Rubiales crude, considering an average diluent purchase price delivered at the Rubiales field of $106.7 / bbl (Light Crude Oil 37 API and Natural Gasoline 81,6 API), plus pipeline fees from the Rubiales field to Coveñas of $7.76 per bbl, less the average Rubiales Blend (Castilla) sale price of $102.19 per bbl, times the Rubiales average blending ratio of around 24%. The increase in dilution cost over the previous period of 2010 is primarily due to the purchasing cost increase of the diluents required to upgrade the Rubiales crude oil, in line with increased WTI international prices.*
(6) *Other costs mainly correspond to royalties on gas production, external road maintenance at the Rubiales field, inventory fluctuation, crude oil trading cost, storage cost and the net effect of the currency hedges of operating expenses incurred in Colombian pesos during the period. See additional comments on page 22 – "Risk Management Contracts".*

(7) *Corresponds to the net effect of the overlift position for the period amounting to $12.7 million, which generated a reduction in the combined production costs of $1.29/boe as explained in "Discussion of 2011 Second Quarter Financial Results – Financial Position – Operating Costs" on page 18.*

4. 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. In addition to its production assets, the Company has a significant investment in oil pipelines in Colombia, including Oleoducto de los Llanos ("ODL") and the new Oleoducto Bicentenario (OBC), currently under construction. The Company, through intensive exploration activity and a large exploration portfolio, is focused on identifying opportunities primarily within the eastern Llanos Basin of Colombia, as well as in other areas in Colombia, Guatemala and northern Peru. Pacific Rubiales has a current gross production of approximately 235,000 boe/d, including natural gas and light and medium oil fields, with interests in 40 blocks in Colombia, 2 blocks in Guatemala and 3 blocks in Peru, totaling approximately 12,562,597 net acres.

Vision

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

Strategy

The Company has an enviable strategic position with 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 with appropriate risk – reward balance, where our knowledge and talents can provide a significant advantage and by the continuous use of the appropriate technology in order to increase and optimize the recovery rates in our existing resource base. The Company will start making inroads on developing the bunker market within Colombia and the supply of finished products to wholesale markets and securing market access by participating in key oil and gas transportation and infrastructure projects such as the OBC pipeline.

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

5. Discussion of 2011 Second Quarter Operating Results

Exploration

During the second quarter of 2011, the Company continued its exploration drilling campaign in the Rubiales-Piriri, Quifa, CPE-6, Abanico and Dindal-Rio Seco Blocks for a total of 13 wells drilled during this period and a success rate of 92%. In the Rubiales- Piriri Block, the Rub-403, Rub-404 and Rub-534 appraisal wells were drilled in the eastern buffer zone outside the commercial area of the Rubiales Field and the Rub-362 appraisal well was drilled in the southern buffer area of the Rubiales Field. In the Quifa southwest area, the Quifa-84, Quifa-114, Quifa-117, Quifa-118, Quifa-119 and the Quifa-120 appraisal wells were drilled in the southwestern and northeastern part of the prospect "H", while the Quifa-141 well was drilled in the southeastern border of the "J" prospect; all these wells confirmed the presence of a hydrocarbon column and reaffirmed the extension of the reservoir in Quifa SW. In the CPE-6 Block, the Guairuro-6 stratigraphic well was drilled in the southern border of the Guairuro prospect; and in the Abanico Block, the Company finished drilling the Gecko-1X exploratory well in the southwestern part of the Block. Also, during the quarter, the Company started drilling the Capira-1X exploratory well, located in the southern part of the Guaduas field In the Dindal Block

During the same period the Company finished the acquisition of 112 km of 2D seismic in the SSJN-3 Block and 560 km in Block 138 in Peru.

Net capital expenditures on exploration activities during the quarter ended June 30, 2011 totaled $117.2 million (2010 - $30.9 million), of which $33.3 million were invested in seismic, $79.5 million in drilling and $4.4 million in other exploratory projects.

During this quarter, the Ministry of the Environment of Colombia granted the Company the required environmental permits for Quifa Southwest and Quifa North. The environmental permit for Quifa Southwest was granted on June 2, 2011, and the permit for Quifa North was granted on June 24, 2011. The Permits allow Pacific Rubiales to continue its development drilling campaign in Quifa Southwest and to proceed with its exploration drilling campaign in Quifa North.

During the first half of 2011, the Company completed the drilling of 33 exploratory wells and acquired a total of 672 km of 2D seismic. Exploration activity for the second half of 2011 includes drilling of 49 additional wells and the acquisition of 2,177 km of 2D seismic and 1,746 km^2 of 3D seismic.

A detailed summary of the exploration activities being developed during the second quarter of 2011 is set out below:

<u>Rubiales-Piriri Block</u>

As part of the appraisal campaign in the block, the Company drilled four appraisal wells in the eastern and southern buffer zone of the Rubiales-Piriri contract. The Rub-403, Rub-404 and Rub-534 wells were drilled in the eastern buffer zone of the Piriri Contract and the Rub-362 appraisal well was drilled in the southern buffer area of the Rubiales Field in the Quifa southwest area. These wells were successful and exhibited net pays varying from 10 to 40 feet and 31% average porosity. The results from these wells will support the reserves certification for this area and the commerciality application for the buffer zone, which is expected to be submitted to Ecopetrol during the third quarter of 2011.

<u>Quifa Block</u>

In the Quifa Southwest commercial area, the Company drilled a total of seven wells: the Quifa-84, Quifa-114, Quifa-117, Quifa-118, Quifa-119 and Quifa-120 appraisal wells were drilled in prospect "H", while the Quifa-141 appraisal well was drilled in prospect "J". Six of these wells successfully showed net pay thicknesses between 13 and 26 feet with porosities between 28% and 31%, confirming the extension of the oil accumulation in the Quifa southwest reservoir to the south and southeast, into the so-called prospect “J”. The Quifa-120 well only showed 5 feet of net pay, and was declared non-economic.

Also, during the second quarter of 2011, and as mentioned before, the Ministry of the Environment of Colombia granted the required environmental permits for Quifa Southwest and Quifa North which will allow the Company to continue its development drilling campaign in Quifa Southwest and proceed with its exploration drilling campaign in Quifa North.

<u>CPE-6 Block</u>

During the second quarter of 2011, the Company drilled the Guairuro-6 stratigraphic well. The well was drilled in the southern part of the Guairuro prospect and only showed 5 feet of net pay, confirming the boundary of the reservoir in this part of the Block. The Guairuro-6 well is the sixth stratigraphic well drilled in the block, and with this well the Company fulfills its exploratory commitment for the Technical Evaluation Agreement (“TEA”) Contract. Also during this period, the Company submitted to the ANH an E&P Contract request for the northern part of the Block. Approval of the E&P contract is expected during the third quarter of 2011.

<u>La Creciente Block</u>

During the second quarter of 2011, the Company re-evaluated the results of the Apamate-1X discovery well. Post-drill maps show an acreage that goes from 1,124 acres to a maximum upside of around 5,266 acres. An extended production test has been conducted in the well since June 17, 2011. To date the well has shown a stable daily production of 8 mmscfg with a choke of 12/64. The Company is now preparing the surface location to drill two appraisal wells on the Apamate discovery during the second half of 2011.

Arauca Block

On July 3, the Company started drilling the Torodoi-1X exploratory well which targeted the Cretaceous Guadalupe and Tertiary Mirador and Carbonera formations. On July 14, the well reached final depth at 7,327 feet MD. The petrophysical evaluation showed an oil-bearing sand interval in the Carbonera C-5 with net pay thickness of 13 feet, 24% porosity and water saturation of 45% without an oil-water contact interpreted. The Company is now planning a production test for this interval to be conducted during the third quarter of 2011. The TORODOI-1X well is the first of two exploration wells of the Contract. The second exploratory well will be drilled during the third quarter of 2011.

Abanico Block

In the Abanico Block, the Company finished drilling the Gecko-1X exploratory well, which targeted the Cretaceous Caballos Formation at an approximate depth of 6,500 feet. Although the well showed presence of oil in the Caballos Formation and gas shows in the Barzalosa Formation, the production tests were negative in both intervals.

Dindal Block

In the Dindal Block, the Company spudded the CAPIRA-1X exploratory well on April 16, 2011, located in the southern reaches of the Guaduas field. The CAPIRA-1X well is the first exploration well drilled by the Company in the Dindal-Rio Seco area, with the fractured Cimarrona limestones as main exploration target, with a planned TD of 8719 feet MD. By June 30, the well had reached a depth of 8,355 feet MD.

Topoyaco Block

During the second quarter, the Company reinterpreted the Topoyaco D sub-thrust prospect, incorporating the results from the Topoyaco 1 and 2 wells. Resources are anticipated by the Company in the Basal Rumiyaco, Villeta and Caballos formations, which have proved to be productive in other parts of the basin. An exploratory well for prospect “D” is planned to be drilled during the third quarter of 2011.

Peru

During the period, the Company finished the acquisition of 560 km of the planned 2D seismic program in Block 138 and started the processing and interpretation of this data in order to update the exploratory evaluation of the block. Preliminary interpretation of field data has allowed the Company to identify three important structures at Cretaceous levels and three leads, involving Paleozoic units. These structures are similar to other producing structures in Central and Northern Peru as well as the eastern Solimöes Basin in Brazil. The Company is processing the existing seismic data to improve the seismic image of the identified structures.

On May 20, 2011 the Company received the approval of the Environmental Impact Study for Block 135, which will allow the Company to start planning and contracting the 714 km 2D seismic program committed for this block.

Guatemala

During the second quarter of 2011, the Company, through the blocks’ operator, Compañía Petrolera del Atlántico S.A. (“CPA”), received approval from Colombia’s Ministry of Energy and Mines with respect to the exploratory program submitted for blocks “N-10-96" and "O-10-96" to develop seismic reprocessing of 300 km of 2D seismic; acquisition and processing of additional 322 km of 2D seismic; 5,270 km of aero-magnetic and aero-gravimetric data; 715 km^2 of remote perception surveys; a surface geology campaign and the beginning of an integrated geological interpretation to define exploratory prospect locations to be drilled in 2012.

Sabanero, Muisca and Cordillera-15 Blocks

During the second quarter of 2011, The Company started evaluating technical information from the Sabanero, Muisca and Cordillera-15 Blocks and, together with Maurel & Prom, has defined the activities to be developed in these blocks during the second half of 2011. These include the drilling of four stratigraphic wells and the acquisition of 283 km^2 3D seismic in the Sabanero Block, drilling one exploratory well in Muisca (Nemqueteba-1X exploratory well, spudded on July 3, 2011) and the acquisition of 227 km^2 of 3D seismic in Cordillera-15.

Exploratory Drilling Activity (Number of Wells)

The Company currently has an outstanding success rate of 92% in the drilling campaign executed on exploratory wells as of June 30, 2011, as follows:

Number of wells (2)	Three Months Ended		Six Months Ended	
	Jun 30 2011	Jun 30 2010	Jun 30 2011	Jun 30 2010
Succesful exploratory wells (1)	0	0	1	4
Succesful appraisal wells	11	0	19	8
Succesful stratigraphic wells	1	0	3	0
Dry wells	1	1	4	2
Total	13	1	27	14
Sucess rate	**92%**	**0%**	**85%**	**86%**

(1) Exploratory wells for the second quarter of 2011 does not include the Capira 1X well in the Dindal Rio Seco. This well will be completed during the third quarter of 2011. During the first quarter of 2011, there was one successful exploratory well: Apamate-1 in the La Creciente block.

(2) Out of the 100 producing wells successfully drilled during 2011, 43 wells were completed during the second quarter of 2011 corresponding to Rubiales (37 wells) and Quifa (6 wells).

Summary of Working Interests and Royalties

As at the date of this MD&A, the Company has working interests in the following oil and gas properties:

License	Net Acres ('000)	Interest	Contract	Royalty
Exploration				
Colombia - Lower Magdalena Basin				
CR-1	184	60%	ANH	(b)
SSJN-3	634	100%	ANH	(b)
SSJN-7	334	50%	ANH	(b)
GUAMA	184	100%	ANH	(b)
SSJN-9	327	(a)	ANH	(b)
CICUCO	85	94%	Ecopetrol	(b)
Colombia - Llanos & Cordillera Basins				
ARAUCA	343	95%*	ANH	(b)
CPE-1	2,446	100%	ANH	Non applicable
LLANOS -7	57	100%	ANH	(b)
COORDILLERA -15	147	(a)	ANH	Non applicable
COORDILLERA -24	620	100%	ANH	(b)
LLANOS - 55	38	100%	ANH	(b)
MUISCA	287	(a)	ANH	(b)
ARRENDAJO	25	32.5%*	ANH	(b)
CPO-1	76	50%*	ANH	(b)
SABANERO	53	(a)	ANH	(b)
CPO-12	283	40%	ANH	(b)
CPO-14	324	62.5%	ANH	(b)
CPO-17	130	(a)	ANH	(b)
CPE-6	751	50%	ANH	Non applicable
Colombia - Caguán & Putumayo Basin				
TOPOYACO	32	(d)	ANH	(b)
CAGUAN -5	119	50%	ANH	(b)
CAGUAN -6	460	60%	ANH	(b)
PUTUMAYO - 9	121	60%	ANH	(b)
TACACHO	297	50.5%*	ANH	(b)
TERECAY	587	100%	ANH	(b)
Peru - Marañon & Ucayali Basin				
Lote 137	1,109	100%	Perupetro	15,01% - 30,01%
Lote 135	1,387	55%*	Perupetro	12,02% - 27,02%
Lote 138	563	55%*	Perupetro	12,02% - 27,02%
Guatemala - Amatique Basin				
N-10-96	55	55%*	Min Minas	(c)
O-10-96	19	55%*	Min Minas	(c)
Exploration and Production				
Colombia - Lower Magdalena Basin				
LA CRECIENTE	37	100%	ANH	(b)
Colombia - Upper & Middle Magadalena Basin				
BUGANVILES	15	49.375%*	Ecopetrol	(b)
Colombia - Llanos Basins				
QUIFA	226	60%	Ecopetrol	(b)
Production				
Colombia - Upper & Middle Magadalena Basin				
LAS QUINCHAS	31	50%*	Ecopetrol	(b)
RIO SECO	19	90.6%	Ecopetrol	20%
DINDAL	24	90.6%	Ecopetrol	20%
PULI B - Puli 7 Well	7	50%	Ecopetrol	20%
ABANICO	16	25%	Ecopetrol	5%
GUÁSIMO	1	100%	ANH	(b)
CAGUAN (Río Ceibas Field)	5	27.27%	Ecopetrol	20%
CHIPALO	32	100%	Ecopetrol	20%
Colombia - Lower Magdalena Basin				
CERRITO	6	(e)	Ecopetrol	20%
Colombia - Llanos Basins				
MORICHE (Mauritia East) MORICHE (Mauritia North 1)	2	37.5%* 87%*	ANH	(b)
PIRIRÍ	33	50%	Ecopetrol	20%
RUBIALES	35	40%	Ecopetrol	20%

a) *The Company holds a 49.999% ownership interest in Maurel & Prom Colombia B.V., which has an interest in the corresponding hydrocarbon licenses in Colombia. See "Maurel & Prom" on page 17.*
b) *Sliding scale as indicated in the table below:*

ROYALTIES ACCORDING TO ACT 756 OF 2002	
DAILY AVERAGE MONTHLY PRODUCTION	**PERCENTAGE**
For production of max 5KBPD	8%
For production higher than 5KBPD and max 125KBPD	X% Where X = 8 + (production KBPD - 5 KBPD)* (0.10)
For production higher than 125KBPD and to max 400KBPD	20%
For a production higher than 400KBPD and to max 600KBPD	Y% Where Y = 20 + (production KBPD - 400 KBPD)* (0.025)
For production higher than 600 KBPD	25%
For the exploitation of heavy crude oil of maximum 15° API, royalties shall be of 75% of applicable royalty for light and medium light crude oil. This rule shall only cover production from new discoveries, incremental production contracts and discovered undeveloped	

***Note**: Quifa SW field is subject to a sliding scale royalty. The Company's share before royalties in the Quifa SW field is 60% and decreases according to a high-prices clause that assigns additional production to Ecopetrol. Both Ecopetrol and the Company are jointly defining the impact of this clause in the production split for second quarter 2011 onwards.*

* *Subject to terms*

c) *Royalties at the two Guatemala blocks correspond to 20% for API of +/- 1% on API of no less than 5%.*
d) *Assignment of 100% to PRE requested from ANH. Subject to approval.*
e) *Assignment of 100% to PetroMagdalena (Alange) requested from Ecopetrol. Subject to Ecopetrol and ANH approval.*

Production

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

Total production during the second quarter of 2011 averaged 221,896 boe/d (88,092 boe/d net after royalties and field consumption) for an increase of 83,516 boe/d (32,990 boe/d net after royalties and field consumption) over the same period in 2010. This represents a 60% growth in operated production, which came about mainly through increased production at the Rubiales, Quifa and La Creciente fields. The following table sets out the second quarter 2011 average production at all of the Company's producing fields:

	Average Q2 2011 Production					
	Gross production net of field consumption		Share before royalties		Net Share after royalties	
Producing Fields	**Q2 2011 boe/d**	**Q2 2010 boe/d**	**Q2 2011 boe/d**	**Q2 2010 boe/d**	**Q2 2011 boe/d**	**Q2 2010 boe/d**
Rubiales / Piriri (1)	169,232	120,594	69,955	52,497	55,964	41,998
Quifa(2)	36,010	2,060	21,487	1,236	19,698	1,162
La Creciente (3)	10,674	10,146	10,449	9,989	10,447	9,987
Abanico (4)	2,286	2,763	673	1,111	646	933
Rio Ceibas (5)	1,778	1,884	480	511	384	406
Dindal / Rio Seco (6)	1,376	670	755	607	627	486
Cerrito (7)	196	79	170	59	170	59
Other Producing fields (8)	344	184	172	85	156	71
Total	**221,896**	**138,380**	**104,141**	**66,096**	**88,092**	**55,102**

(1) Net of internal consumption at the field.

(2) The Company's share before royalties in the Quifa SW field is 60% and decreases according to a high-prices clause that assigns additional production to Ecopetrol. Both Ecopetrol and the Company are jointly defining the impact of this clause in the production split from April 2011 onwards, therefore the production doesn't yet reflect the impact on the Company's share.

(3) Royalties on the gas production from La Creciente field are payable in cash and accounted as part of the production cost. Royalties on the condensates are paid in kind, representing a small impact in the net share after royalties.

(4) The Company started sales of CO2-free gas, produced by the northernmost wells in the field; and installed a CO2 treatment plant in May 2011, which increased gas sales to 1.1MMcfd. In addition, Ecopetrol agreed to drill one development well during the third quarter of 2011, and is considering the drilling of two additional wells during the next twelve months

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

(6) The Compressed Vehicular Gas sales averaged 0.8 MMcfd in June 2011. Remaining gas is currently being injected and used for power generation. The Company is evaluating the construction of central power generation facilities for internal consumption and sales to the local electrical grid.

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

(8) Other producing fields located in the Puli, Moriche, Quinchas, Buganviles and Guasimo blocks.

The operated production increase during the second quarter of 2011 is mainly attributable to the drilling of 37 producing wells at the Rubiales field and 6 producing wells at the Quifa field. The completion of the CPF-Quifa allowed the Quifa field's production to reach 36,000 bbl/d by the end of June 2011. The completion of CPF2 at the Rubiales field raised production capacity to 190,000 bbl/d.

Production at La Creciente natural gas field increased by 5.2%, and the facilities were upgraded in order to improve the quality of the gas. The production in the field is now only limited by the constraints in the natural gas downstream transport network.

New Facilities Construction

During the second quarter of 2011, the following new facilities were constructed and brought into operation, which contributed to the increase in production levels:

Rubiales field

- New water treatment facilities at CPF-2 in order to handle an incremental volume of 150,000 bbl/d of water.
- 12.7 km of new roads.
- 13.1 km of flow lines between 10” and 24”.
- 22 new electrical power sub-stations.
- 11.1 km of new field electric distribution network.
- 80,000 bbl/d additional water injection capacity.

Quifa field:

- 6.2 km of new roads.
- 15.3 km of flow lines between 10” and 24”.
- The water transfer system was stabilized with the commissioning of four pumps to handle 250,000 bbl/d.

La Creciente field:

- New gas-gas exchanger in order to warranty handling of up to 65 MMscfd to sales specifications.
- New scrubber exchanger to increase handling capacity to 67 MMscfd of gas.
- 1.8 km of 6” flow lines between the Apamate-1 well and the central station.

Historical Production Milestone

Production continued its growth trend, and as of June 30, 2011 the Company's gross production reached 228,300 boe/d, which is the result of the continuous growth in production of heavy oil in the Rubiales/Piriri and Quifa Blocks, supported by the operation of the ODL pipeline and the Company’s 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 5,700 standard cubic feet per barrel) from the La Creciente block and other smaller fields. As of August 7, 2011 gross production exceeded 235,000 boe/day.

Supply and Sales Balance

The following is the Company´s reconciliation of boe produced vs. boe sold for the period ended on June 30, 2011:

Reconciliation of Barrels Produced and Purchased Vs. Barrels Sold

	2Q 2011	
Inventory Movements	**Total boe Net**	**Aver. day Net**
Ending inventory as of March 31, 2011	1,922,425	
Transactions in Q2 2011		
Net oil and gas production	8,016,345	88,092
Settlement of overlift position from March 31, 2011 (1)	(75,376)	(828)
Purchases of diluents	1,565,873	17,207
Purchases of oil for trading	456,423	5,016
Total sales	(9,917,882)	(108,988)
Overlift position as of June 30, 2011 (2)	(30,280)	(333)
Volumetric compensation and operational gains/losses	(17,778)	(195)
Ending inventory as of June 30, 2011 (3)	**1,919,750**	

(1) This volume corresponds to the settlement of the overlift position for crude oil as of March 31, 2011, which resulted in a lower volume of sales during the period it was settled.
(2) This volume corresponds to an overlift position of 30,280 boe of crude oil and gas as of June 30, 2011, which will be settled during future periods.
(3) Corresponds to crude oil inventory in tanks as of the end of June 30, 2011 at the fields and Coveñas Terminal as well as permanent inventory in the pipeline systems.

Commercial Activity

Second Quarter 2011 Market Overview

- The second quarter of 2011 was subject to considerable levels of intraday volatility. WTI Nymex prices increased to $102.3/bbl in from $94.6/bbl in the first quarter of 2011 (+$7.7/bbl); meanwhile Brent Dated prices were stronger than WTI, reaching $117/bbl vs. $105.4/bbl in the first quarter of 2011 (+$11.6/bbl). In turn, widening WTI-Brent spread to $14.7/bbl compared to $10.8/bbl in the first quarter of 2011 (+$3.9/bbl).

- At the beginning of the quarter, WTI Nymex prices were higher due to indications of stronger macroeconomic results in the US economy, and ongoing geopolitical tensions in MENA (Middle East and North Africa) countries. Later, crude prices were quickly depressed due to perceptions of weaker economic recovery in the US, and the debt crisis in the European Union. In the meantime, Brent prices strengthened even more from Libyan light-sweet crude disruptions of about -1.2 million bbl/d and a decline in UK North Sea production of about 100,000 bbl/d in the second quarter.

- In addition, there was great expectation of an OPEC production increase, because of the impact of high crude prices on demand. On June 8, 2011, OPEC held a members meeting in which they failed to reach an accord on production increases. In response to OPEC´s position, IEA announced the release of 60 million bbl, or 2 million bbl/d of oil over 30 days from the end of that week, in order to supply the ongoing disruption of Libyan crude oil.

- Throughout this period, WTI continued losing its role as a crude oil reference, because of its dislocation to other physical markets. A discount for WTI compared to similar crudes is expected to persist due to the increase of Canadian crude supplies and transportation and storage bottlenecks, limiting the movement from Cushing to the Mid West and to the Gulf coast refineries.

- As a consequence, Latin American crudes and USGC crudes strengthened their prices compared to WTI. For example, Maya crude oil, which is used as a heavy crude reference, strengthened its price compared to WTI to WTI + $0.5/bbl compared to WTI against -$4.6/bbl in the first quarter of 2011.

Crude Oil and Gas sales

In the second quarter of 2011, WTI NYMEX reached an average of $102.34/bbl compared to the $78.05/bbl average in the second quarter of 2010, a 31% increase.

- In the second quarter of 2011, the Company exported sixteen cargoes and eighteen small parcels of crude oil, 76% Castilla blend crude (6,829,873 bbl), 18% Vasconia blend crude (1,633,631 bbl), and 6% Rubiales (499,605 bbl), representing a total volume of 8,963,109 bbl.

- The average realized oil price for Castilla blend crude oil during the second quarter of 2011 was $101.85/bbl, higher by 53% than the $66.73/bbl realized in the second quarter of 2010. The average differential vs. WTI NYMEX improved $11.45/bbl during the second quarter of 2011 vs. the second quarter of 2010. In this period the Company exported nine cargos of Castilla blend crude oil, two delivered to the US Gulf Coast, four to the Caribbean, one to Europe and two to Asia. In this quarter, three cargoes were sold in parcels of 1,000,000 bbl, also improving logistic economics. As well, the Company sold two cargoes of 500,000 bbl and eighteen small parcels through other exporters of Vasconia blend crude oil. The average realized oil price for these sales was $110.52/bbl, higher by 58% than the $69.92/bbl realized in the second quarter of 2010. All of these volumes were mainly sold to the US. The average differential vs. WTI NYMEX improved by $12.6/bbl during the second quarter of 2011 vs. the second quarter of 2010.

- During the second quarter of 2011, the Company maintained its flexible commercial strategy by selling 67,930 bbl of Rubiales 12.5°API in the Colombian domestic market. In the period, the Company sold 499,000 barrels in five small cargoes of 12.5°API crude oil trucked from the Rubiales field to the Atlantic Oil Terminal in Barranquilla, at an average price of $96.60/bbl, taking advantage of the strength of fuel oil prices. These five cargoes were delivered to the Caribbean and the US Gulf Coast.

- For purposes of securing diluents for Rubiales crude oil, the Company continued local purchases of light crude oils in the eastern Llanos (14,348 bbl/d average vs. 8,497 bbl/d average in the second quarter of 2010), supplemented with natural gas for logistic strategic reasons (2,677 bbl/d average), maintaining the average diluents factor around 19.7%.

- During the second quarter of 2011, the volume of natural gas sold to the local market increased to 63.3 MMscf/d, from a volume of 61 MMscf/d during the same period in 2010 (a 4% increase). These sales were mainly from La Creciente field, at an average price of $5.58/MMbtu (equivalent to $5.59/MMscf), representing a premium of 31% over the MRP of $4.26 /MMbtu, and 28% over the Henry Hub natural gas prices during the same period. Natural gas from La Creciente field was sold mainly (96%) to power generators located in Cartagena and Barranquilla and the remaining 4% was sold to industries connected to the trunk gas pipeline.

- The natural gas sales price is referenced to Maximum Regulated Price (MRP) for gas produced in La Guajira field. The MRP is modified every six months for the second quarter of 2011, MRP was $4.26/MMBTU. The MRP changes every 6 months based on the previous half-year variation of the US Gulf Coast Residual Fuel No.6 ,1.0% sulfur, Platts.

- On April 20, 2011, the Company entered into a firm gas sale contract from the Apamate reservoir (La Creciente Block) for 2013, 2014 and 2015 with a fixed quantity of 45,000 MMBTUD, at an average price of MRP + 25%. Taking into account the MRP in effect for the second quarter of 2011 ($4.26/MMBTU), the estimated value of the contract is approximately $260 million.

- The combined realized oil and gas price for the Company for the second quarter of 2011 was $96.54/boe, higher by 58% than the $60.96/boe realized in the same period of 2010.

Average benchmark crude oil and natural gas prices for the second quarter ended June 30, 2011 were as follows:

	2Q		
Average Crude Oil Reference Prices	2011 ($/bbl)	2010 ($/bbl)	°API
Domestic Market	$98.57	$66.80	12.5
WTI NYMEX (Weighted Average of PRE Cargoes)	$102.13	$77.54	38
Vasconia (Weighted Average of PRE Cargoes and Parcels) (1)	$110.52	$69.62	24
Castilla (Weighted Average of 9 Cargoes PRE) (2)	$102.19	$66.73	19
Rubiales Export. 12.5 (Weighted Average of PRE Cargoes) (3)	$96.60	$65.99	12.5
Combined Realized International Oil Sales Price	**$103.39**	**$67.08**	**18.5**
PRE Natural Gas Sales ($/mmbtu)	$5.60	$4.69	N/A
Combined Realized Oil and Gas Sales Price	**$96.54**	**$60.96**	**N/A**
Regulated Gas Price ($/mmbtu)	$4.26	$3.89	N/A
WTI NYMEX ($/Bbl)	$102.34	$78.05	
Henry Hub average Natural Gas Price ($/mmbtu)	$4.35	$4.31	

(1) Weighted average price of two cargoes and eighteen parcels of Vasconia crude oil exported during the second quarter of 2011.
(2) Weighted average price of nine Castilla crude oil cargoes exported during the second quarter of 2011
(3) Weighted average price of five Rubiales (12.5°API) small cargoes exported during the second quarter of 2011.

Transport of Hydrocarbons

The following are the milestones achieved on product transported during the second quarter of 2011:

- The Company transported 121,765 bbl/d through the different pipelines and trucking systems, including 16,684 bbl/d of diluents; 13,342 bbl/d third party crude oil through Guaduas Facilities; 79,897 bbl/d was transported via ODL-Ocensa pipeline system at maximum capacity utilization, and 11,841 bbl/d by trucks, of which 6,047 bbl/d were transported to Guaduas-ODC pipeline system and 5,794 bbl/d to different destinations by trucks. Pipeline use represents a savings of up to $17.4/bbl in transportation costs for the Company when compared to truck transportation.
- The Company was able to transport 79,897 bbl/d through the OCENSA pipeline and 13,616 bbl/d through the ODC pipeline, representing savings of $31 million and $12 million, respectively.
- The Company loaded 8,017 truck trips without traffic accidents or environmental incidents.
- The Guaduas Facility handled and transported 22,097 bbl/d of crude oil from the Company and third parties, generating an operational profit of $2.27/bbl for the Company, totaling $4.6 million for the period.

6. Project Status

STAR Project in Quifa

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

The pilot area has already been selected; it will have a five spot pattern in 25 acres, located in the vicinity of the Quifa 38 Cluster. After finishing geological and reservoir modelling, four synchronizing–producer and one injector wells will be drilled.

Preliminary simulations have been done using the updated geological and reservoir model and kinetic reactions equations available for the Rubiales field. Results have indicated the feasibility of carrying out the pilot test in Quifa, and of obtaining high recovery factors.

As of the date hereof, major equipment is already installed and connected, including production manifold, gas separator, chillers, and a Strafford plant for handling acid fluids. The STAR project pilot test is expected to be operational in August 2011.

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 Colombia, 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 the Llanomulsion and for a new formulation developed by Ecopetrol´s research and development affiliate Petroleum Research Institute (“ICP”) were performed at the Rubiales field pilot plant. Both formulations were also tested at the main pumping units of ODL with excellent results. The next phase of this project includes pumping 40,000 bbl of emulsion from the Rubiales field to the Cusiana Station, through the ODL pipeline. This phase involves the construction of additional facilities at CPF1, the ODL Rubiales Pumping Station, and at the OCENSA Cusiana Station. 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 dehydrated and the crude oil treated for commercialization.

During the Second Quarter, facilities for manufacturing Llanomulsion in CPF-1 were completed. Coordination between Meta Petroleum, ODL, OCENSA and the ICP is under way. The industrial test is intended to be performed when an operational window for ODL and OCENSA is available in the second half of 2011. 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 92,118,260 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 a pipeline branch to Cusiana Station already in operation, construction of two booster stations and increase storage capacity at the Rubiales Pumping Station. As of June 30, 2011 the expansion was 85% completed. This includes two new pumping units, four 50,000 bbl tanks for diluents in the Rubiales Main Station and a new power plant delivering 19.4 MW under a BOOT contract. Construction of booster station No. 1 is well advanced. As of the date of this report, commissioning of the first two units in this booster station is under way.

During the second quarter of 2011, the pipeline system pumped a total of 19,703,519 bbl and from this volume, 7,270,991 bbl corresponded to the Company's crude oil.

On July 24, 2011, a pumping record of 255,290 bbl/d was achieved. This record was the result of new impellers installed in the main pumping units of the pipeline, the use of a drag reducing agent and the improved capacity of the OCENSA pipeline, which is connected to the ODL.

With the intention of increasing operating capacity and reducing dependence on truck transportation of diluents, ODL is conducting a feasibility study for a heated oil pipeline. Also, conceptual engineering is being developed in order to transport diluted crude of 15° API to Cusiana Station. Additional diluent will be added at this point in order to bring the fluid to 18° API, according to OCENSA specs.

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

The Company incorporated PEL, a wholly-owned subsidiary, in 2010. PEL is responsible for constructing and operating a new power transmission line of 230 kilovolts to connect the Rubiales Field 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 220 MVA that will be used in oil production and transportation activities. Total capital expenditures for this project have been estimated at $143 million, of which up to 70% is expected to be project financed.

Main activities for the project during the second quarter of 2011 include:

- Verified 100% of the selected location for towers. Also the civil design for all towers was completed.
- 25% of aluminum conductors were shipped to the storage areas.
- Completed fabrication of 30% of suspension towers.
- More than 70% of right of ways have been duly negotiated.
- Construction will start in the second half of 2011, once the environmental permit is granted.
- Financing: Details have already been worked out with two banks and execution is pending on the environmental license and execution of a Take or Pay agreement with ODL.

Oleoducto Bicentenario – Bicentennial Pipeline

The Company has a 32.88% equity interest in OBC, acquired in November 2010. The 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 operation of Colombia's newest oil pipeline transportation system, which will run from Araguaney, in the Casanare Department of central Colombia, to the Coveñas Export Terminal in the Caribbean.

The new pipelines will add 450,000 bbl/d to the capacity of the existing pipeline systems connecting the Eastern Llanos Basin to the export markets, which are projected to reach full capacity as the increase in planned production from Colombian producers materializes in the mid-term. The project has been structured as a 5 phase project.

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

It is estimated that the first two phases of this project will require an aggregate investment of $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 multi-lateral financing, as well as to access the Colombian capital markets.

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

During the second quarter of 2011, 100% of the required pipe for phase 1 of the project (Araguaney – Banadia pipeline), arrived at Colombian ports. In addition, acquisition of rights of way reached 93% as of March 31, 2011 and the Ecopetrol contractor started mobilization of construction equipment. Construction will start as soon as the environmental license is fully in place.

As of the date of this report, the partners of OBC are negotiating a joint investment agreement to continue with Phases 2 and 3 of the project, which include construction of 300 km of loops to the existing Caño Limón-Coveñas Pipeline, as well as upgrading of booster stations, between Banadía and Coveñas. Incremental capital expenditures for these two phases has been estimated at $1.6 billion, which will bring pumping capacity in the OBC pipeline to 240,000 bbl/d.

7. Maurel & Prom

On May 6, 2011 PRE-PSIE CÖOPERATIEF U.A. ("PRE-PSIE"), a Dutch subsidiary beneficially owned by Pacific Rubiales and Les Establissements Maurel & Prom, S.A. ("MAUREL"), successfully completed the acquisition by PRE-PSIE of a 49.9999% interest in Maurel and Prom Colombia B.V. for cash consideration of $63.4 million and certain exploratory commitments. Maurel and Prom Colombia B.V owns the following hydrocarbon interests located on-shore in Colombia:

- 100% participation in the Sabanero Block located in the central region of Colombia in the Department of Meta.
- 100% participation in the Muisca Block located in the central region of Colombia in the Departments of Boyaca and Cundinamarca.
- 50% participation in the SSJN-9 Block located in the northern region of Colombia in the Departments of Bolivar, Cesar and Magdalena. The remaining 50% interest is currently held by HOCOL S.A.
- 50% participation in CPO-17 Block located in the central region of Colombia in the Department of Meta. The remaining 50% interest is currently held by HOCOL S.A.
- 100% participation in the COR-15 Block located in the central region of Colombia in the Department of Boyaca.

8. Capital Expenditures

Capital expenditures during the quarter ended June 30, 2011 totaled a net amount of $307.7 million (2010 - $134.7 million), of which $109 million was invested in the expansion and construction of production infrastructure; $117.2 million went into exploration activities including seismic, aerogravimetry, aeromagnetometry and drilling; $50 million were invested in production drilling activities; and $31.5 million were invested in other projects. Details on the capital expenditure program as of June 30, 2011 follow:

	Net capital expenditures (Thousands of US$)			
	Q2		Year to date	
	2011	2010	2011	2010
Production facilities	$ 109,011	$ 73,886	$ 170,354	$ 110,546
Exploration drilling including seismic acq.	117,225	30,870	158,751	44,290
Development drilling	49,956	29,163	106,014	60,083
Other objects (STAR, Llanomulsion, Gas export)	31,513	825	34,076	825
Total capital expenditures	**$ 307,705**	**$ 134,744**	**$ 469,195**	**$ 215,744**

9. Proved and Probable Oil and Gas Reserves

The total proved and probable oil equivalent reserves of the Company as of June 30, 2011, is 347.54 million bbl gross (before royalties) or 301.83 million bbl net to the Company. Oil equivalent is expressed in thousands of barrels (Mbbl). Gas volumes are expressed in billion cubic feet (Bcfg) and, when expressed in oil equivalent, were converted using 5,700 cubic feet of gas equivalent to one (1) bbl. The 2010 Reserves Reports were prepared in accordance with NI 51-101 and published on the Company's website on March 11, 2011.

10. Discussion of 2011 Second Quarter Financial Results

Revenues

Revenue during the second quarter of 2011 totaled $957.5 million, or $96.54 per boe (2010 - $356.8 million, or $60.96 per boe), an increase of 168% in comparison to the same period of 2010. Net sales continued to grow mainly due to the 60% increase in production and construction of facilities at the Rubiales, Quifa and La Creciente fields, coupled with better realized oil and gas prices throughout the second quarter of 2011 as explained in the table below.

	Q2			
	2011	2010	Difference	% Change
Total of boe sold (Mboe)	9,918	5,854	4,064	69%
Avg. Combined Price - oil & gas and trading ($/bbl)	96.54	60.96	35.58	58%
Total Revenue (000$)	957,509	356,848	600,661	168%

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

Increase due to volume	247,740	41%
Increase due to price	352,921	59%
	600,661	

Operating Costs

Operating costs for oil and gas during the second quarter of 2011 were $355.7 million (2010 - $133.2 million). Production costs per boe for the second quarter of 2011 totaled $35.88 per boe, an increase of 60% in comparison to the same period of 2010. The increase over the previous period of 2010 is primarily due to the significant increase of 44% in the diluents required to upgrade the Rubiales crude oil from 12.5° to 18.5° API, in line with increased international WTI prices (cost of diluents in 2011 - $14.73/bbl vs 2010 – $10.26/bbl). Transport costs for the quarter also increased by 47% in comparison to the prior period of 2010 mainly due to higher volume of diluents and Rubiales crude oil transported via tank truck due to increased production, coupled with an increase in the overall trucking transport costs in Colombia during 2011.

The $35.88 per boe consists of production cost of $5.18, transportation cost of $8.84, dilution cost of $14.73, overlift of $1.29 and other costs of $5.84. The increase in costs was offset by a $7.1 million positive effect resulting from foreign currency risk management contracts recorded against operating expenses.

Depletion, Depreciation and Amortization

Depletion, depreciation and amortization costs during the second quarter of 2011 were $178.1 million (2010 - $90.6 million). The increase over the previous quarter of 2010 was primarily due to an increase in oil and gas property costs incurred subject to depletion and increase in production. Included in the costs subject to depletion is $0.84 billion (2010 - $0.21 billion) of future development costs that are estimated to be required to bring proved undeveloped reserves to development.

General and Administrative

General and administrative expenses for the second quarter ended June 30, 2011 were $43.5 million (2010 - $25 million), and the increase is mainly attributable to:

- The significant increase in operations that resulted in hiring of new personnel and adjustment of salaries according to market standards. The number of direct and indirect employees in the second quarter of 2011 increased 38% to a total of 1,588 compared to 1,147 in the same period in 2010.
- The 7% appreciation of the Colombian peso against the US dollar when compared to the same period of 2010. The majority of the general and administrative costs are incurred in Colombian pesos and are therefore subject to fluctuation when converted to the US dollar.
- The accelerated depreciation of administrative equipment ($3.2 million in the second quarter of 2011), due to the anticipated relocation of offices to a new building in Bogota, Colombia.

Share-Based Compensation

Share-based compensation was $0.7 million as a result of the granting of 65,000 (2010 - 3,198,500) fully vested options in the second quarter of 2011 compared to $31.9 million in the previous year. The decrease is due to a decrease of the number of options granted. All stock options outstanding as of June 30, 2011 are completely vested and exercisable and the fair values are calculated using the Black-Scholes option pricing model.

Foreign Exchange

Foreign exchange gains or losses primarily resulted from the translation of monetary assets or liabilities which are denominated in Colombian pesos. The Company's functional currency for the Canadian operations is the Canadian dollar, and the functional currency for the Colombian operations is the US dollar. The foreign exchange loss incurred in the second quarter is primarily due to the appreciation of the Colombian pesos against the US dollar.

Finance Cost

Finance cost includes interest on bank loans, convertible debentures, senior notes, revolving credit commitment fees, finance leases and fees on letters of credit. For the second quarter of 2011, interest expense totaled $23.7 million compared to $20.4 million for the same period 2010. The higher interest expense over the same quarter of 2010 is mainly due to interest incurred on promissory notes and commitment fees paid on the Company's unused Revolving Credit Facility. No new long-term debt was entered into during the second quarter of 2011.

Income Tax Expense

The tax rate in Canada is 28.25% and in Colombia 33% of taxable income. The Colombian Congress passed a tax reform on December 29, 2010 eliminating the 30% special tax benefit starting as at January 2011. However, the new law allows certain taxpayers 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 and once the contract has been signed. 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.

Income tax expense increased during the three month period ended June 30, 2011, which is in line with increased revenues and operating income. The effective tax rate is lower than the statutory rate of 33% primarily due to the non-deductible costs for tax purposes such as share-based compensation costs, equity tax and gain on risk management contracts.

Current income tax represents the estimated cash income taxes payable for the period. Current income tax increased to $140.7 million from $29.6 million during the same period of 2010, which was primarily due to increased operating income and includes the special deduction for investment in assets eligible for the special tax benefit.

Net Earnings (Loss)

Net earnings for the three months ended June 30, 2011 totaled $349.4 million (2010 - $14.4 million). The Company´s second quarter 2011 financial results were impacted by a number of non-cash items totaling $82.7 million. These non-cash items are mainly related to unrealized mark-to-market gains on derivatives of $84.9 million, share-based compensation of $0.7 million, and foreign exchange loss of $1.5 million. These non-cash items may or may not materialize in future periods. Excluding these items, the Company's adjusted net earnings was $266.7 million, or $0.99 per basic common share.

Cash Flow from Operations

The Company continued to generate positive cash flow from operations as a result of the increase in production together with the increase in the combined realized oil and gas price. The cash flow from operations during the quarter ended June 30, 2011 totaled $116.3 million, as indicated in the table below. This increase is primarily attributable to the 57% increase in the combined net back in the second quarter of 2011 as compared to the same period in 2010 ($60.66 per boe in the second quarter of 2011 versus $38.51 per boe in the same period of 2010), as well as the significant increase in production. The increase in net back is due to higher realized prices from $60.96 per boe in 2010 to $96.54 per boe in 2011.

	Three Months Ended June 30		Six Months Ended June 30	
	2011	2010	2011	2010
Cash flow from operations	116,273	101,896	436,076	359,496
$ per share, basic	0.43	0.45	1.63	1.38

Financial Position

<u>EBITDA</u>

EBITDA during the three months ended June 30, 2011 totaled $558.4 million, which represents a significant increase of 181% compared to the second quarter 2010 EBITDA of $198.6 million, mainly generated from international sales (85%); EBITDA from gas and domestic sales contributed 13% and 2%, respectively. Second quarter 2011 EBITDA represents a 58% margin in comparison to total revenues for the period (June 30, 2010 – 56% margin).

<u>Debt</u>

On April 13, 2011, the Company closed the amendment to its existing unsecured revolving credit facility (the "Revolving Credit Facility"), which was increased from $250 million, initially committed by the lenders in April 2010 to $350 million. The amendment was limited to the same lenders under the Revolving Credit Facility and, in addition to increasing the amount of the facility, the Company extended the term to April, 2013 and reduced the applicable commitment fees and the applicable margin. To date, the Company has not drawn down any funds from this credit facility. Funds will be utilized as needed to take advantage of opportunities in the Colombia E&P sector that may become available and to fulfill the Company's business strategy.

The applicable margin and commitment fees will continue to be determined in accordance with the rating assigned to the Company's senior debt securities by Standard & Poor's Ratings Group and Fitch Inc. Based on the Company's current rating and expected usage, the commitment fee will be reduced from 100 bps to 75 bps and the applicable margin from 325 bps to 250 bps over LIBOR. Subject to customary acceleration events set forth in the credit agreement relating to the Revolving Credit Facility, or unless terminated earlier by the Company without penalty, repayment of outstanding principal on the Revolving Credit Facility will be made in full on April 26, 2013.

As of June 30, 2011, the Company had issued standby letters of credit for operational and exploration commitments for a total of $225.6 million (June 30, 2010 – $143.8 million). Most of these bank guarantees are related to light oil purchases and exploration commitments.

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.

On July 5, 2011, Standard & Poor's Ratings Services raised the Company's corporate credit rating on the Company to BB from BB-. They also raised their rating on the Company's $450 million Senior Unsecured Notes due 2016 to 'BB'. Standard and Poor's reported that the stable outlook reflects their view that the Company will continue to generate strong financial performance and that the Company's positioning will allow it to continue executing its growth strategies.

Securities

During the three months ended June 30 2011, no convertible unsecured subordinated debentures were converted into common shares in the capital of the Company.

On June 13, 2011, the Company announced a cash dividend in the aggregate of $25 million, or $0.093 per common share. The dividend was paid on June 30, 2011 to shareholders of record as of June 17, 2011; the ex-dividend date in Canada was June 15, 2011.

Outstanding Share Data

Issued and Fully Paid Common Shares

As at June 30, 2011, 269,423,353 common shares were issued and outstanding.

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

On March 6, 2011, the Company announced that it had filed with the Toronto Stock Exchange (the "TSX") a Notice of Intention to commence a normal course issuer bid to purchase for cancellation up to a maximum of 11,598,513, or 4.3%, of the total issued and outstanding common shares in the capital of the Company as of March 31, 2011. The Company has not purchased any common shares to date pursuant to the normal course issuer bid.

Stock Options and Warrants

As at June 30, 2011, 14,450 warrants to acquire an equal number of common shares were outstanding and exercisable and 24,443,361 stock options were outstanding, of which all were exercisable.

Liquidity and Capital Resources

Liquidity

Funds provided by operating activities for the quarter ended June 30, 2011 totaled $116.3 million (2010 – $101.9 million), The increase in cash flow in 2011 was the result of the increase in production and higher combined crude oil and gas sale prices. The Company has been generating cash flows from operations from the sale of crude oil and natural gas and continues to plan for increased future production.

As of June 30, 2011, the Company had working capital of $308 million, mainly composed of $338.9 million of cash and cash equivalents, $631.2 million of account receivables, $116.8 million of inventory, $1.4 million of income tax receivable, $0.9 million of prepaid expenses, $636 million of accounts payable and accrued liabilities, $139.2 million of income tax payable, and $6 million of current portion of finance lease obligations.

On April 27, 2010, the Company closed the syndication of the Revolving Credit Facility. On April 13, 2011, the Company closed an amendment to the Revolving Credit Facility. As a result of the demand generated amongst the lending syndicate, the amount of the Revolving Credit Facility was increased from the $250 million initially committed by the lenders to $350 million, and the Company extended the term of the Revolving Credit Facility to April, 2013 and reduced the applicable commitment fees and the applicable margin.

As at June 30, 2011, 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 5), the Company will pay for the expansion plan with its own cash flow. However, if additional resources are required, there are possible sources of funds available to the Company to finance additional capital expenditures and operations including the Revolving Credit Facility, existing working capital and incurring new debt, and the issuance of additional common shares, if necessary.

11. Commitments and Contingencies

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

Disclosure concerning the Company's significant commitments can be found in note 18 to the interim condensed consolidated financial statements. The Company has no off-balance sheet arrangements.

12. Risk Management Contracts

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

Commodity price risk

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

Asset as at June 30, 2011

Instrument	Term	Volume (bbl)	Floor/ceiling or strike price ($/bbl)	Benchmark		Fair value
Zero cost collars	January 2012 to December 2012	3,114,200	80/120 - 121	WTI	$	1,057
Put option	July 2011 to December 2011	6,420,000	70-75	WTI		2,747
	Total				**$**	**3,804**
	Short-term				$	3,804
	Long-term					-
	Total				**$**	**3,804**

Liabilities as at June 30, 2011

Instrument	Term	Volume (bbl)	Floor/ceiling or strike price ($/bbl)	Benchmark		Fair value
Call option	November 2011 to December 2012	10,160,000	109.50 -118.80	WTI	$	(62,615)
Zero cost collars	January 2012 to December 2012	1,517,200	80/120 - 121	WTI		(223)
	Total				**$**	**(62,838)**
	Short-term				$	(18,749)
	Long-term					(44,089)
	Total				**$**	**(62,838)**

Liabilities as at December 31, 2010

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

For the three and six months ended June 30, 2011, the Company recorded a gain of $84.9 million and a loss of $7.7 million respectively (2010 - $5.1 million and $10.2 million in gains) on commodity price risk management contracts in net earnings. Included in these amounts were $86.2 million of unrealized gain and $5.4 million of unrealized loss (2010 – $11.9 million and $18.7 million in unrealized gains) representing the change in the fair value of the contracts, and $1.3 million and $2.5 million of realized losses (2010 - $6.8 million and $8.5 million) resulting from premiums paid.

Foreign currency exchange risk

The Company is exposed to foreign currency fluctuations in Colombian pesos (COP). 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 had the following currency risk management contracts outstanding that qualify for cash flow hedge accounting:

As at June 30, 2011

Instrument	Term		Notional amount	Floor-ceiling (COP/$)		Fair value
Currency collars	July to December 2011	$	270,000	1860 - 1930	$	16,250

As at December 31, 2010

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

The effective portion of the change in the fair value of the above currency hedges is recognized in other comprehensive income as unrealized gains or losses on cash flow hedges. The effective portion is reclassified as production and operating expenses in net earnings in the same period as the hedged operating expenses are incurred. During the three and six months ended June 30, 2011, $12.9 million and $20 million (2010 - $2 million and $10 million) of unrealized gains respectively were initially recorded in other comprehensive income, and $7.1 million and $7.6 million respectively (2010 - $1.7 million and $1.7 million) were subsequently transferred to production and operating cost when the gains became realized. The Company excludes changes in fair value due to the time value of the investments and records these amounts along with hedge ineffectiveness in foreign exchange gains or losses in the period that they arise. During the three and six months ended June 30, 2011, $3 million and $4.9 million (2010 - $4.7 million and $5.7 million) of ineffectiveness was recorded as foreign exchange loss.

Additional disclosure about the Company's risk management policies and contracts can be found in Note 21 to the interim consolidated financial statements. The Company has no off-balance sheet arrangements.

13. Selected Quarterly Information

(In thousands of $ except per share amounts or as noted)	2011		2010				2009 (1)	
	Q2	Q1	Q4	Q3	Q2	Q1	Q4 (Restated (2))	Q3
Financials:								
Net sales	$ 957,509	$ 583,549	$ 516,730	$ 408,535	$ 356,848	$ 379,431	$ 211,650	$ 156,557
Net earnings (loss) for the period	349,375	(69,593)	79,376	95,102	14,438	76,127	3,218	(63,107)
Earnings (loss) per share								
- basic	$ 1.30	$ (0.26)	$ 0.30	$ 0.36	$ 0.05	$ 0.30	$ 0.02	$ (0.29)
- diluted	$ 1.20	$ (0.26)	$ 0.28	$ 0.34	$ 0.05	$ 0.28	$ 0.02	$ (0.29)

(1) 2009 comparative figures prepared in accordance with Canadian GAAP.
(2) 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.

14. New Accounting Pronouncements

First Time Adoption of IFRS

The Company's interim condensed consolidated financial statements as at and for the three and six months ended June 30, 2011 have been prepared in accordance with International Financial Reporting Standard 1 *First-time adoption of IFRS* ("IFRS 1") and International Accounting Standard 34 *Interim Financial Reporting* ("IAS 34") as issued by the International Accounting Standards Board.

The Company adopted IFRS in 2011 with a transition date of January 1, 2010. The interim condensed consolidated financial statements have been prepared using the accounting policies the Company expects to adopt in its annual financial statements for the year ending December 31, 2011. These accounting policies and the effect of the first-time adoption of IFRS have been disclosed in the interim condensed consolidated financial statements for the three months ended March 31, 2011.

Reconciliations from Canadian GAAP to IFRS

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

Reconciliation of Consolidated Statement of Financial Position as at June 30, 2010

		Jun. 30, 2010 Cdn GAAP	Adjustment IFRS	Jun. 30, 2010 IFRS
Current assets	$	930,493	(11,873)	918,620
Non-current assets		2,433,523	111,022	2,544,545
Total assets	**$**	**3,364,016**	**99,149**	**3,463,165**
Current liabilities		438,988	(14,255)	424,733
Non-current liabilities		1,030,707	10,281	1,040,988
Total liabilities	**$**	**1,469,695**	**(3,974)**	**1,465,721**
Shareholders' equity		1,894,321	103,123	1,997,444
Total Liabilities and shareholders' equity	**$**	**3,364,016**	**99,149**	**3,463,165**

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

		Dec. 31, 2010 Cdn GAAP	Adjustment IFRS	Dec. 31, 2010 IFRS
Current assets	$	984,393	(16,669)	967,724
Non-current assets		2,870,693	115,712	2,986,405
Total assets	**$**	**3,855,086**	**99,043**	**3,954,129**
Current liabilities		801,712	(17,780)	783,932
Non-current liabilities		1,018,302	7,070	1,025,372
Total liabilities	**$**	**1,820,014**	**(10,710)**	**1,809,304**
Shareholders' equity		2,035,072	109,753	2,144,825
Total Liabilities and shareholders' equity	**$**	**3,855,086**	**99,043**	**3,954,129**

Reconciliation of Consolidated Statement of Income for the three months ended June 30, 2010

	Jun. 30, 2010 Cdn GAAP	Adjustment IFRS	Jun. 30, 2010 IFRS
Total revenue	359,700	(2,852)	356,848
Total expense	264,356	**36,583**	**300,939**
Income before taxes	**95,344**	**(39,435)**	**55,909**
Taxes	(47,416)	5,945	(41,471)
Net income	**47,928**	**(33,490)**	**14,438**

Notes for reconciliations from Canadian GAAP to IFRS

1. Oil and gas properties and exploration and evaluation assets

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

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

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

2. Consolidation of Transmeta

Under Canadian GAAP, the Company consolidated Transportadora Del Meta S.A. ("Transmeta") as a variable interest entity. Under SIC 12 requirements, consolidation of special purpose entities is determined based on control. The

Company has concluded it does not control Transmeta as of January 1, 2010 and therefore consolidation has been reversed.

3. Asset retirement obligation

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

4. Deferred income tax

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

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

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

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

5. Land acquisition

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

6. Equity-accounted investments

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

7. Functional currency

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

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

The transition from Canadian GAAP to IFRS did not materially change the underlying cash flows of the Company with the exception that the Company no longer consolidates the operating results of Transmeta as described in 2 above. As a result of the reversal of consolidation of Transmeta, the Company's net cash provided by operating activities was reduced by $1.4 million for the three months ended June 30, 2010.

15. Related-Party Transactions

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

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

a) In June 2007, the Company entered into a 5-year lease agreement with Blue Pacific Assets Corp. for administrative office space in one of its Bogota, Colombia locations. Monthly rent expense of $57 is payable to Blue Pacific under this agreement. Three directors and officers of the Company control, or provide investment advice to the holders of, 67.2% of the shares of Blue Pacific. During the three months ended June 30, 2011 the Company also entered into a 10-year agreement with an entity controlled by Blue Pacific for additional office space in Bogota with a monthly rent of $429.

   The Company also has accounts receivable of $1.8 million from Blue Pacific as at June 30, 2011 (December 31, 2010 - $16) related to certain administrative costs paid by the Company on behalf of Blue Pacific. In addition, the Company paid $0.5 million and $1.1 million to Blue Pacific during the three and six months ended June 30, 2011 respectively (2010 - $0.5 million and $0.5 million) for air transportation services.

b) As at June 30, 2011, the Company had trade accounts receivable of $2.7 million (December 31, 2010 - $1.7 million) from Proelectrica, 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 Pacific Power Generation Corp (previously Ronter Inc.). Revenue from Proelectrica in the normal course of the Company's business was $6.3 million and $10.2 million for the three and six months ended June 30, 2011 respectively (2010 - $2.8 million and $10.2 million).

c) During the three and six months ended June 30, 2011, the Company paid $13.4 million and $24.3 million respectively (2010 - $7.7 million and $19.6 million) to Transmeta in crude oil transportation costs. In addition the Company has accounts receivable of $3.9 million (December 31, 2010 - $4.1 million) from Transmeta as at June 30, 2011. Transmeta is controlled by a director of the Company.

d) Loans receivable in the aggregate amount of $583 (December 31, 2010 - $322) are due from three management directors and three officers of the Company as at June 30, 2011. The loans are non-interest bearing and payable in equal monthly payments over 48 months. The loans were issued by the Company to these individuals in connection with costs incurred by these individuals as a result of their relocation.

e) The Company has entered into aircraft transportation agreements with Petroleum Aviation Services S.A.S., a company controlled by a director of the Company. During the three and six months ended June 30, 2011, the Company paid $2.4 million and $3.8 million respectively (2010 - $1.3 million and $3.2 million) in fees as set out under the transportation agreements.

f) The Company received $0.3 million and $0.6 million from ODL during the three and six months ended June 30, 2011 respectively (2010 – $3.9 million and $3.9 million) with respect to certain administrative services and rental equipment and machinery. The Company does not have any outstanding accounts receivable from ODL with respect to reimbursement of power supply costs as at June 30, 2011 (December 31, 2010 – $3.1 million).

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

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

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

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

During the quarter ended June 30, 2011, there has been no change in the Company's ICFR that has materially affected, or is reasonably likely to materially affect, the Company's ICFR. The Company has continually had in place systems relating to DC&P and ICFR and will continue to monitor such procedures as the Company's business evolves.

17. Outlook

The Company will continue working on increasing its production and transportation capacity. Expansion of current facilities and the drilling of new production wells will allow the Company to increase its gross production to 265,000 boe/d, 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.

The Company's exploration activities will continue in 2011 and includes the drilling of 49 additional wells, the acquisition of 2,177 km of 2D seismic and 1,746 km^2 of 3D seismic in a total of 26 blocks.

18. Additional Financial Measures

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

The following table shows the reconciliation of funds flow from operations to cash flow from operating activities for the second quarter 2011 as compared with the second quarter of 2010:

	Three Months Ended June 30		Six Months Ended June 30	
	2011	2010	2011	2010
Cash flow from operating activities	116,273	101,896	436,076	359,496
Changes in non-cash working capital	(283,929)	(46,486)	(230,833)	61,726
Funds flow from operations	400,202	148,382	666,909	297,770

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

	Three Months Ended June 30		Six Months Ended June 30	
	2011	2010	2011	2010
Net earnings	349,375	14,438	279,782	90,565
Adjustments to net earnings				
Income taxes expense	82,291	41,471	131,665	71,801
Foreign exchange loss (gain)	1,523	8,241	(2,430)	(5,284)
Finance cost	23,781	20,420	46,930	34,296
Loss (gain) on risk management contracts	(84,896)	(5,144)	7,738	(10,161)
Loss (gain) from equity investment	7,701	(2,259)	11,089	(1,075)
Other expense (income)	(265)	(1,565)	3,070	322
Share-based compensation	705	31,853	47,392	72,675
Equity tax	-	522	68,446	1,044
Depletion, depreciation and amortization	178,124	90,608	327,184	176,368
EBITDA	558,339	198,585	920,866	430,551

19. Legal Notice – Forward-Looking Information and Statements

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

Statements concerning oil and gas reserve estimates may also be deemed to constitute forward-looking statements to the extent they involve estimates of the oil and gas that will be encountered if the property is developed. Boe may be misleading, particularly if used in isolation. A Boe conversion ratio of 5.7 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.

20. Risks and Uncertainties

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

- fluctuating oil and gas prices;
- cash flows and additional funding requirements;
- global financial conditions;
- exploration and development;
- operating hazards and risks;
- reserve estimates;
- transportation costs;

- disruptions in production;
- political risk;
- environmental factors;
- title matters;
- dependence on management;
- changes in legislation;
- repatriation of earnings;
- enforcement of civil liabilities;
- competition; 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.

21. Abbreviations

The following list of abbreviations is used in this document

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