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PACIFIC RUBIALES ENERGY CORP.
MANAGEMENT DISCUSSION AND ANALYSIS

November 8, 2011
Form 51-102 F1
For the three month and nine month periods ended September 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 30.

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 third 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 contain a detailed description of the Company's first annual reporting under IFRS. All comparative percentages are between the quarters ended September 30, 2011 and September 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 30. All references to net barrels or net production reflect only the Company's share of production after deducting royalties and the partner's working interest. A list of abbreviations for oil and gas terms is provided on page 32.

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 15.

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. ("**Meta**"), 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 Peru. Pacific Rubiales has a current gross field production of approximately 239,000 boe/d, with working interests in 41 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. Third Quarter Highlights

During the third quarter of 2011, the Company continued its trend of production growth and exploratory success, leveraging its technical know-how and operational expertise. Nevertheless, the third quarter 2011 production was affected by two labour disturbances causing unscheduled operational disruptions at the Rubiales and Quifa fields, as previously announced on July 20, September 20 and 22, and October 26, 2011. Despite these disruptions, 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, as well as pursuing an ambitious exploration and production ("**E&P**") investment program, under the umbrella of the Company's paramount strategic focus: Growth.

- **Production continues to grow.** Average gross field production in the third quarter of 2011 was 219,136 boe/d, 87,159 boe/d net after royalties and field consumption, 55% higher than the same period of 2010. However, the third quarter 2011 production was affected by two labour disturbances causing unscheduled operational disruptions at the Rubiales and Quifa fields, which resulted in a total gross production loss of 1,343,084 bbl during this period, representing 491,933 bbl net to the Company (5,347 bbl/d).

- **Significant improvement in operating netbacks.** Crude oil operating netback during the third quarter of 2011 was $56.12/bbl, 44% higher in comparison to the same period in 2010 ($38.89/bbl), due to higher realized prices. Natural gas operating netback was $34.15/boe, higher by 34% in comparison to the same period of 2010.

- **Strong financial results.** The third 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 third quarter of 2011 were $193.7 million, or $0.71 per common share, compared with net earnings of $113.2 million for the third quarter of 2010, or $0.43 per common share. Adjusted net earnings for the third quarter of 2011 were $176 million, compared to $104.6 million in the third quarter of 2010. Revenues increased to $828.3 million compared to $408.5 million recorded for the same period in 2010.

- **EBITDA doubled.** EBITDA for the third quarter of 2011 totaled $465 million, which represents a two-fold increase as compared to EBITDA for the previous year's third quarter of $218.1 million. EBITDA for the third quarter of 2011 represents a 56% margin in comparison to total revenues for the period. Funds flow from operations increased to $350 million in the third quarter of 2011, compared to $161 million in the third quarter of 2010.

- **Continued focus on exploratory activities with a success rate of 83%.** During the third quarter, the Company drilled a total of 18 exploratory wells, 15 wells were successful. Also, the Company commenced the acquisition of 526 km^2 of 3D seismic and 739 km of 2D seismic with a total net investment of $64.5 million.

- **Important growth in the Company's net proved and probable reserves (2P).** During the third quarter, the Company received independent reserves evaluation reports for the Rubiales-Piriri, Quifa and Sabanero blocks, which established that the net proved and probable reserves ("**2P**") have grown to a total of 350 million barrels of oil equivalent ("**MMboe**") as of the evaluation dates (June 30 and September 15, 2011), an increase of 15.2% (without deducting production for the period) when compared to the reserves reports dated February 28, 2011.

- **Resource evaluation of 25 exploration blocks.** During the third quarter, the Company received independent resource assessment reports for the Company's exploration blocks in Colombia (21), Peru (3) and Guatemala (1), resulting in a Net Best Estimate for Contingent and Prospective Resources of 2,777.45 MMboe for those exploration blocks. The prospectivity of the exploration portfolio together with 2P reserves sets the foundation to build the Company´s future growth.

- **Inventory levels.** The standard operational inventory of the Company is 1.9 million bbls and during the third quarter the Company's inventory increased by a net of 734,219 bbl which remained unlifted at the end of the quarter and have since been sold in cargoes for October and December. During October 2011, 800,000 bbls from third quarter inventory were sold at an average realized price of $104.4 per bbl, generating gross revenue of $83.5 million which will be reflected along with the related costs in the earnings of the fourth quarter 2011.

- **Investment in capital expenditure activities.** Capital expenditures during the quarter ended September 30, 2011 totaled a net amount of $276.7 million (2010 - $200.0 million), of which $124.9 million were invested in the expansion and construction of production infrastructure; $64.5 million went into exploration activities including seismic, aerogravimetry, aeromagnetometry and drilling in Colombia, Peru and Guatemala; $52.9 million for development drilling; and $34.4 million were invested in other projects, including STAR.

- **Continued development of producing facilities.** During the third quarter of 2011, new facilities were built at the Rubiales and Quifa fields to reach a total of 197,000 bbl/d operated production level and 40,000 bbl/d, respectively.

- **Joint Venture in Peru.** On October 12, 2011 the Company announced the signing of a letter of intent with Les Establisssements Maurel & Prom S.A. ("**Maurel & Prom**") to acquire a 50% working interest in the exploration contract for Block 116 located in northeastern Peru, whereby the Company will assume a full carried obligation of up to $75 million, which is initially intended to cover the first and second wells of the contract for Block 116. Under the terms of the letter of intent, once operatorship of the block is transferred to the Company, we will be entitled to receive a reimbursement of these costs through cash flows derived from future hydrocarbon production from the block. The transaction is subject to government and regulatory approvals, as well as legal and financial due diligence to the Company's satisfaction.

- **Investment in Guyana.** On October 13, 2011, the Company purchased 58,720,000 common shares in the capital of CGX Energy Inc. ("**CGX**"), a company listed on the TSX Venture Exchange, at a price of C$0.70 per common share, for an aggregate investment of C$41.1 million. CGX is a Canadian-based oil and gas exploration company focused on the exploration for oil in the Guyana/Suriname Basin. The Company holds approximately 18% of the issued and outstanding common shares in the capital of CGX.

- **Filing for BDR Listing in Brazil.** On October 6, 2011, the Company announced that it has filed before the Comissao de Valores Mobiliarios (the "**CVM**"), the Brazilian regulatory entity in charge of supervising public issuers, and the Brazilian stock exchange called BM&FBOVESPA S.A., the documentation required for the trading of Brazilian Depositary Receipts (the "**BDRs**") representing the Company's common shares.

- **Temporary Incentive Conversion Rate Increase for the Debentures.** On October 25, 2011 the Company provided notice to all holders of the Company's C$240 million convertible, unsecured, subordinated debentures due on August 29, 2013 (the "**Debentures**") of an incentive program to convert their Debentures at the current conversion rate plus an additional number of the Company's common shares with value equal to C$200 per C$1,000 face value of Debentures.

- **Cash dividend paid to shareholders on September 30, 2011.** On September 8, 2011, the Company announced a cash dividend in the aggregate of $25 million, or $0.093 per common share. The dividend was paid on or about September 30, 2011 to shareholders of record as of September 20, 2011.

3. Financial and Operating Summary

<u>Financial Summary</u>

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

(in thousands of US$ except per share amounts or as noted)	Three Months Ended Sept 30 2011	2010	Nine Months Ended Sept 30 2011	2010
Oil and gas sales [1]	**$ 828,285**	$ 408,534	**$ 2,369,343**	$ 1,144,813
EBITDA [2]	**465,057**	218,152	**1,385,923**	648,703
EBITDA Margin (EBITDA/Revenues)	**56.1%**	53.4%	**58.5%**	56.7%
Per share - basic ($) [4]	**1.72**	0.83	**5.15**	2.48
Net earnings	**193,720**	113,152	**473,502**	203,717
Per share - basic ($) [4]	**0.71**	0.43	**1.76**	0.78
- diluted ($)	**0.68**	0.41	**1.68**	0.75
Adjusted Net earnings from operations [3]	**176,039**	104,599	**576,967**	253,438
Per share - basic ($) [4]	**0.65**	0.40	**2.13**	0.96
Funds Flow from Operations	**349,930**	161,428	**1,016,839**	459,198
Per share - basic ($) [4]	**1.29**	0.61	**3.78**	1.76

Adjusted Net Earnings from Operations

Net earnings for the third quarter of 2011 of $193.7 million included a number of non-operating items totaling $17.7 million mainly related to mark-to-market gains on derivatives, share-based compensation, and foreign exchange losses. These non-operating items may or may not materialize in future periods. The adjusted net earnings from operations follow:

(in thousands of US$ except per share amounts or as noted)	Three Months Ended September 30 2011	2010	Nine Months Ended September 30 2011	2010
Net earnings (loss) as reported	**$ 193,720**	$ 113,152	**$ 473,502**	$ 203,717
Non-operating items [5]				
Loss (gain) on risk management contracts	**(63,027)**	10,639	**(55,289)**	478
Share-based compensation	**1,075**	652	**48,467**	73,327
Equity tax	**-**	522	**68,446**	1,566
Foreign exchange (gain) loss	**44,271**	(20,366)	**41,841**	(25,650)
Total non-operating items	**$ (17,681)**	$ (8,553)	**$ 103,465**	$ 49,721
Adjusted earning from operations [3]	**$ 176,039**	$ 104,599	**$ 576,967**	$ 253,438

1) *See additional details in section 5 "Discussion of 2011 Third Quarter Operating Results" – Reconciliation of barrels produced and purchased vs. barrels sold on page 11.*
2) *See Section 9 – "Discussion of 2011 Third Quarter Financial Results – EBITDA" on page 21 and "Additional Financial Measures" on page 30.*
3) *Adjusted earnings from operations are a non-IFRS financial measure that represents net earnings adjusted for certain items of a non-operational nature including non-cash items. The Company evaluates its performance based on adjusted net earnings from operations. The reconciliation "Adjusted Net Earnings from Operations", lists the effects of certain non-operational items that are included in the Company´s financial results. Adjusted net earnings from operations may not be comparable to similar measures presented by other companies. See "Additional Financial Measures" on page 30.*
4) *The basic weighted average number of common shares outstanding for the third quarter ended September 30, 2011 and 2010 was 270,967,710 (fully diluted –298,413,561) and 264,065,489 (fully diluted –276,961,528), respectively.*
5) *See additional details explained in Section 9 – Discussion of 2011 Section Third Quarter Financial Results" on page 17.*

Operating Summary

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

Operating Netback Crude Oil and Gas

Combined crude oil and gas operating netback improved during the third quarter of 2011 was $53.68/boe, 45% higher as compared to the same period of 2010. Crude oil operating netback during the third quarter of 2011 was $56.12/bbl, 44% higher in comparison to the same period in 2010, due to higher realized prices. Our natural gas operating netback was $34.15/boe, 34% higher in comparison to the same period of 2010:

	Three months ended September 30			
	2011	**2011**	**2011**	**2010**
	Oil	**Gas**	**Combined**	**Combined**
Average net production (after royalties and field consumption)[1]	**75,853**	**11,306**	**87,159**	**56,404**
Average daily production sold (boe/day)[1]	**90,341**	**11,212**	**101,553**	**71,257**
Operating netback ($/boe) [2]				
Crude oil and natural gas sales price	95.09	36.81	88.66	62.32
Cost of production [3]	5.59	2.83	5.29	3.83
Transportation (trucking and pipeline) [4]	12.44	0.08	11.08	6.54
Diluent cost [5]	16.23	-	14.44	10.94
Other costs [6]	2.57	(0.54)	2.23	4.09
Overlift/Underlift [7]	2.14	0.29	1.94	(0.19)
Operating netback ($/boe)	**56.12**	**34.15**	**53.68**	**37.11**

(1) *See comments below.*
(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 $4.2 per bbl of Rubiales crude, considering an average diluent purchase price delivered at the Rubiales field of $104.8/bbl (Light Crude Oil 37º API and natural gas at 81.6º API), plus pipeline fees from the Rubiales field to Coveñas of $7.76 per bbl, less the average Rubiales Blend (Castilla) sale price of $93.97 per bbl, times the Rubiales average blending ratio of 22.7%. The increase in dilution cost over the previous period of 2010 ($3.24/bbl) is primarily due to the increase in the price of diluents, in line with increased WTI 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 23 – "Risk Management Contracts".*
(7) *Corresponds to the net effect of the overlift position for the period amounting to $18 million, which generated a reduction in the combined production costs of $1.94/boe as explained in "Discussion of 2011 Third Quarter Financial Results – Financial Position – Operating Costs" on page 18.*

Volume Allocation for Certain Fields

a) Additional Production Share in Quifa SW field

The Company's share before royalties in the Quifa SW field is 60% and it may decrease when the high-prices clause in the Quifa Association Contract that assigns additional production to Ecopetrol is triggered. The additional Ecopetrol share is generated when the WTI oil price is higher than a reference price, as described in the Contract, after cumulative oil production for each commercial field reaches 5,000,000 bbl gross, including royalties. It is effectively a sliding-scale overriding royalty interest which burdens Meta's participation interest. During the first half of 2011, the cumulative production of the Quifa SW field reached the 5,000,000 bbl of oil threshold. The participation interest of the Parties when the high prices clause is triggered until depletion will be calculated using the equation below:

PI = (P-Po)/P X 0.30

Where:
PI = Ecopetrol Additional Participation Interest,
P = current oil price (WTI) in US$, and
Po = Po $_{(n-1)}$ x (1 + I $_{(n-2)}$)

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

On September 27, 2011, Ecopetrol and the Company agreed to begin an arbitration process to define the interpretation due to the uncertainty of this clause and its effect in the production split. In the meantime, both companies have agreed to apply the ANH formula to assign the additional share to Ecopetrol, from April 2011, until the arbitration settlement is concluded. Based on the ANH formula, the additional production share to Ecopetrol totals 542,697 bbl, for the period covering April 3 to September 30, 2011. This volume was recognized in the third quarter 2011 Consolidated Statement of Income as an overlift. The above volume of 542,697 bbl will be reimbursed according to the corresponding provisions in the Quifa Association Contract signed between the parties.

b) Deferred Production – Rubiales and Quifa Fields

The Company filed a claim before Ecopetrol requesting the payment of 191,103 bbl of crude oil production (net after royalties and field consumption) estimated at $14.1 million, calculated at the fair value price at the field. This claim is due to a number of operational reasons. The Company has not yet recorded in the Consolidated Statement of Income the volume claimed. However, the Company has a reasonable expectation that this claim will be resolved in its favour.

4. Company Overview

Profile

Pacific Rubiales, a Canadian-based company and producer of natural gas and heavy crude oil, owns 100 percent of Meta, a Colombian oil branch which operates the Rubiales/Piriri and Quifa oil fields in the Llanos Basin in association with Ecopetrol; and Pacific Stratus, 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 Peru. Pacific Rubiales has a current gross field production of approximately 239,000 boe/d, including natural gas and light and medium oil fields, with interests in 41 blocks in Colombia, 2 blocks in Guatemala and 3 blocks in Peru as well as an equity interest in an E&P company operating in Guyana.

Vision

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

Strategy

The Company has an enviable strategic position with a balanced 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 an appropriate risk – reward balance, where our knowledge and talents can provide a significant advantage and through the use of appropriate technology 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 Third Quarter Operating Results

Exploration

During the third quarter of 2011, the Company continued its ambitious exploration program, participating in the drilling of a total of 18 wells on the Rubiales-Piriri, Quifa, Sabanero, Arauca, Muisca and Dindal Blocks, and undertaking extensive seismic and geophysical operations on other blocks in Colombia, Peru and Guatemala to delineate future drilling prospects. The Company holds a 49.999% interest in Maurel & Prom Colombia B.V. (“**Maurel & Prom Colombia**”), which holds a 100% participation interest in the Sabanero, Muisca and COR-15 Blocks, and a 50% participation interest in the SSJN-9 and CPO-17 Blocks.

Three successful appraisal wells were drilled in the eastern and southern buffer zone of the Rubiales-Piriri contract. The wells encountered net pay zones ranging from 11 to 17 feet, with average porosities of 31%, confirming extension of the Rubiales reservoir and supporting the recent reserve certification and commerciality application for the buffer zone.

The Company also drilled three successful appraisal wells in Quifa SW area, encountering net pay zones ranging from 14 to 32 feet. These wells extend the existing production area of the Quifa SW field to the northeast and southwest.

In the Quifa North area, the Company drilled six appraisal wells and two exploration wells in the quarter. Seven of the wells were successful, encountering net pay zones ranging from 11 to 32 feet and porosities from 29% to 35%. One of the Quifa North appraisal wells (Opalo-6) was non-economic with only two feet of net pay encountered. The successful wells are currently under extended production tests and their results confirm the hydrocarbon potential of the Quifa North area. During the fourth quarter of 2011 the Company will continue drilling in the area, with nine additional exploration wells planned (including exploration, appraisal and stratigraphic). The Company has started preparing documentation to support the commerciality application for this portion of the Quifa Block.

On the Sabanero Block, the operator Maurel & Prom Colombia drilled the EST-1A stratigraphic well, identifying 20 feet of net pay and confirming extension of the Sabanero prospect 2.2 km northeast of the original Sabanero-1 discovery well. Maurel & Prom Colombia is currently drilling a second stratigraphic well on the block (Sab-Strat-2).

On the Arauca Block, the Company drilled the VACO-1x exploration well. The well reached total depth (TD) in late September but failed to encounter hydrocarbons and was abandoned. An earlier well on the block (Torodoi-1x) which had indicated net pay failed to test hydrocarbons and has been suspended pending additional evaluation. On the Muisca Block, operator Maurel & Prom Colombia drilled the unsuccessful Nemqueteba-1x exploration well. The wells drilled on these two blocks fulfill work commitments for the current exploration phase. On the Dindal Block, the Company finished drilling the CAPIRA-1x exploration well encountering an indicated 25 feet net pay. Subsequent testing failed and the well has been suspended pending further evaluation.

In the Guama Block, the Company started hydraulic-frac workover in the Pedernalito-1X exploration well that was drilled in 2010. The frac operation was successful.

Two exploration wells spudded in the third quarter are currently drilling: the Apamante-2 appraisal well on the La Creciente Block; and the Yaraqui-1x exploration well on the Topoyaco Block, operated by Trayectoria Oil and Gas.

Exploratory Drilling Activity (Number of Wells)

During the period, the Company had a success rate of 83% in its exploration and development drilling campaign as of September 30, 2011, as follows:

Number of wells	Three Months Ended Sept 30 2011	Sept 30 2010	Nine Months Ended Sept 30 2011	Sept 30 2010
Succesful exploratory wells	4	0	6	2
Succesful appraisal wells	10	1	30	6
Succesful stratigraphic wells	1	1	5	7
Dry wells	3	0	9	3
Total	18	2	50	18
Sucess rate	**83%**	**100%**	**82%**	**83%**

Exploratory Wells

No of wells	Well Name	Type	Block	Area / Field / Prospect
1	Rub-551	Appraisal	Rubiales	Southern Border Buffer Zone
2	Rub-557	Appraisal	Piriri	Eastern Buffer Zone
3	Rub-558	Appraisal	Piriri	Eastern Buffer Zone
4	Quifa-113	Appraisal	Quifa	Quifa SW – Southwest Prospect E
5	Quifa-136ST	Appraisal	Quifa	Quifa SW – Northeast Border Prospect H
6	DW-2	Appraisal	Quifa	Quifa SW – Northeast Border Prospect D
7	Opalo-1	Exploration	Quifa	Quifa North – Prospect Q
8	Opalo-2	Appraisal	Quifa	Quifa North – Prospect Q
9	Opalo-3	Appraisal	Quifa	Quifa North – Prospect Q
10	Opalo-4	Appraisal	Quifa	Quifa North – Prospect Q
11	Opalo-5	Appraisal	Quifa	Quifa North – Prospect Q
12	Opalo-6	Appraisal	Quifa	Quifa North – Prospect Q
13	Ambar-4	Appraisal	Quifa	Quifa North – Prospect F
14	Azabache-1	Exploration	Quifa	Quifa North – Prospect P
15	EST-1A	Stratigraphic	Sabanero	2.2 km Northeast of Sabanero-1X Well
16	VACO-1X	Exploration	Arauca	Exploration Targets in C-5 and Mirador Fm.
17	Nemqueteba-1X	Exploration	Muisca	Nemqueteba prospect
18	Capira-1X	Exploration	Dindal	Cimarrona Fm.

In August 2011, the Company received ANH approval for the conversion of the northern portion of Block CPE-6 from a TEA to an E&P Contract covering an area of approximately 240,000 hectares. The corresponding E&P contract was signed on September 26 with a work commitment of 480 km 2D seismic or 300 km^2 3D seismic and one exploration well required during the first 36 month exploration phase. With this E&P Contract in hand, the Company will proceed to accelerate the exploration drilling in order to confirm the prospectivity of the block.

Elsewhere in Colombia during the quarter, the Company had an active program of 2D and 3D seismic acquisition on blocks CPO-12, CR-1, SSJN-7, COR-15 and COR-24. These and additional aero-magneto-gravimetric geophysical data acquisition along with complementary surface geology and geochemistry, are designed to delineate future prospects for drilling.

In Peru, the acquisition and interpretation of extensive seismic data over Block 138 has confirmed the existence of six structures at the Cretaceous level and three leads involving Paleozoic units. These structures are similar in character to producing structures in central and northern Peru as well as the eastern Solimöes Basin in Brazil. The Company is currently in the final stages of interpretation and expects that a well location will be selected and submitted for environmental permits in the near future. The Company expects to drill a well on this block in the third quarter of 2012, depending on the approval of the environmental permits by the Peruvian authorities. In Block 135, the Company has submitted a request for the acquisition of a revised 2D seismic survey, in order to comply with the exploration commitments for this block. The Company expects to begin this survey in the first quarter 2012.

In Guatemala during the third quarter 2011, the Company, through the blocks' operator, Compañía Petrolera del Atlántico S.A. ("**CPA**"), started the contracting phase for seismic data acquisition for blocks "N-10-96" and "O-10-96". Final scopes for these programs are: 289 km of 2D seismic reprocessing, 324 km of additional 2D seismic acquisition, 10,540 km of aero-magnetic and aero-gravimetric data, 715 km^2 of remote perception surveys, as well as a field campaign of surface geology and acquisition/analysis of rock and fluid samples. Regulatory delays on the program have pushed the first well spud plans out to the second quarter 2013.

Production

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

Total gross field production during the third quarter of 2011 averaged 219,136 boe/d (87,159 boe/d net after royalties and field consumption) for an increase of 75,019 boe/d (56,404 boe/d net after royalties and field consumption) over the same period in 2010. This represents a 52% growth in gross field production, which came about mainly through increased production at the Rubiales, Quifa and La Creciente fields.

However, in the third quarter of 2011 production was impacted by two unscheduled disruptions at the Rubiales and Quifa fields caused by the unlawful activity of third party union groups, as announced on July 20, September 20, September 22, and October 26, 2011, which resulted in a total gross field production loss of 1,343,084 bbl, representing 491,933 bbl net to the Company (5,347 bbl/d) during this period. The Company restarted operations at both fields on July 20 and September 22, 2011, respectively, taking a week to raise production back to normal levels.

The following table sets out the third quarter 2011 average production at all of the Company's producing fields:

	Average Q3 Production (in 000s)					
	Total field production		Share before royalties[1]		Net Share after royalties	
Producing Fields	**Q3 2011 boe/d**	**Q3 2010 boe/d**	**Q3 2011 boe/d**	**Q3 2010 boe/d**	**Q3 2011 boe/d**	**Q3 2010 boe/d**
Rubiales / Piriri	167,343	125,945	68,958	54,329	55,166	43,463
Quifa[2]	35,222	3,109	20,996	1,866	19,241	1,754
La Creciente [3]	11,053	9,351	10,860	9,351	10,857	9,349
Abanico [4]	2,082	2,650	656	713	633	642
Rio Ceibas [5]	1,692	1,834	457	497	366	400
Dindal / Rio Seco [6]	1,279	610	740	553	620	442
Other Producing fields [7]	465	616	290	377	276	354
Total	**219,136**	**144,115**	**102,957**	**67,686**	**87,159**	**56,404**

(1) Share after royalties is 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. On September 27, 2011, Ecopetrol and the Company agreed to start an arbitration process to define the interpretation of this clause and its effect in the production split. In the meantime, both companies have agreed to apply the ANH formula to assign the additional share to ECP, from April 2011, until the arbitration settlement is concluded. Therefore the third quarter production does not reflect the impact on the Company's share. See additional comments on page 5 – Volume Allocation for Certain Fields section.

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

(4) The total natural gas production reached was 2.021 MMscfd during the third quarter and the natural gas sales averaged 0.98 MMscfd. Ecopetrol agreed to drill one development and one injector well during the fourth quarter of 2011, and also is considering drilling two additional wells during the next twelve months. The Company started the EPC of a new water treatment plant

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

(6) The increase in gross production relative to third quarter of 2010 is caused by inclusion of natural gas produced in the field, which was included in this report starting second quarter of 2011. The Compressed Vehicular Gas sales averaged 0.8 MMscfd in June 2011. Additional gas is trucked and sold to nearby town of Guaduas. Remaining gas is currently being injected and used for power generation. The increase in production is partly due to services completed in some of the producing wells and the start-up of natural gas sales as mentioned above. Other producing fields located in the Cerrito, Puli, Moriche, Quinchas, Buganviles, and Guasimo blocks.

The production increase during the third quarter of 2011 is mainly attributable to the drilling of 27 producing wells at the Rubiales field and 15 producing wells at the Quifa SW field. The completion of the CPF-Quifa allowed the Quifa field's production to reach 40,000 bbl/d by the end of September 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% as compared to the second quarter of 2011 and by 16% as compared to the third quarter of 2010 due to an increase in demand. The production in the field is now only limited by the constraints in the natural gas downstream transport network and domestic markets.

New Facilities Construction

During the third quarter of 2011, new facilities were built at Rubiales and Quifa SW fields to reach a total of 190,000 bbl/d gross field production capacity (1.8 million bbl/d of water treatment), and 40,000 bbl/d (0.3 million bbl/d of water treatment), respectively. Additional details are set out below:

Rubiales field

- Oil treatment capacity at Rubiales field reached 190,000 bbl/d
- New water treatment facilities in CPF-2 of 150,000 bbl/d reaching 1.8 million bbl/d
- The water transfer line between CPF-1 and CPF-2 went into operation providing more flexibility in the water injection system.
- 120,000 bbl/d additional water injection capacity.
- Other facilities include:
    - 4.4 km of new roads.
    - 29.7 km of flow lines between 10" and 36".
    - 30 new electrical power sub-stations.
    - 70.3 km of new power distribution network.

Quifa field

- Oil and water treatment capacity in the Quifa CPF increased as a result of:
    - New dehydration train
    - The water transfer system was stabilized with the commissioning of four pumps to handle 250,000 bbl/d.
    - 21.7 km of new roads.
    - 23.3 km of flow lines between 10" and 30".

La Creciente

- The bidding process for the expansion of production facilities to 80 MMscf was approved and is currently ongoing.

Historical Production Milestone

Production continued to grow, and as of September 7, 2011 the Company reached a historical milestone of 242,000 boe/d. The continuous growth is the result of the production potential of heavy oil in the Rubiales/Piriri and Quifa Blocks and 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 November 7, 2011 gross field production exceeded 239,000 boe/d.

Supply and Sales Balance

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

Reconciliation of Barrels Produced and Purchased Vs. Barrels Sold

	3Q 2011	
Inventory Movements	**Total boe Net**	**Aver. day Net**
Ending inventory as of June 30, 2011	1,919,750	21,097
Transactions in Q3 2011		
Net oil and gas production	8,018,680	87,159
Settlement of overlift position from June 30, 2011 (1)	30,280	329
Purchases of diluents	1,215,883	13,216
Purchases of oil for trading	837,760	9,106
Total sales	(9,342,859)	(101,553)
Overlift position as of September 30, 2011 (2)	(30,641)	(333)
Volumetric compensation and operational gains/losses	5,116	56
Ending inventory as of September 30, 2011 (3)	**2,653,969**	

(1) This volume corresponds to the settlement of the overlift position for crude oil as of June 30, 2011, which resulted in a lower volume of sales during the period it was settled.

(2) This volume corresponds to a net overlift position of 333,206 boe of crude oil and gas as of September 30, 2011, which will be settled during future periods.

(3) Corresponds to crude oil inventory in tanks as of the end of September 30, 2011 at the fields and Coveñas Terminal as well as permanent inventory in the pipeline systems. The Company recognizes revenue and the related costs on crude oil production when lifting has occurred and the title on the inventory has been transferred. The standard operational inventory of the Company is 1.9 million bbl and during the third quarter, the Company`s inventory increased by a net 734,219 bbl which remained unlifted at the end of the quarter and have since been sold in cargoes for October and December. During October 2011, 800,000 bbls were sold at an average realized price of $104.4 per bbl, generating gross revenue of $83.5 million which will be reflected along with the related costs in the earnings of the fourth quarter of 2011.

Commercial Activity

Third Quarter 2011 Market Overview

- During the third quarter, weak economic growth in the United States and increasing market pressure from the Euro zone debt crisis have lowered confidence levels in the markets and have led to a stronger dollar in turn exerting a downward pressure on oil prices.

- WTI prices declined in third quarter of 2011 to $89.5/bbl from $102.3/bbl in 2Q11 (-$12.8/bbl); meanwhile Brent Dated prices reached $113.4/bbl vs. $117.0/bbl in 2Q11 (-$3.6/bbl). In turn, the WTI-Brent spread widened to $23.9/bbl from $15.2/bbl in the second quarter of 2011 (+$8.6/bbl). Throughout the third quarter, the WTI trend of dislocation to other physical markets continued, mainly due to limited transportation facilities to distribute the crude from Cushing to the refineries. During this period, there was mid-sour and heavy crude scarcity and a marginal improvement in refining margins in the US Gulf Coast ("**USGC**"), creating support for Castilla crude demand and prices. There was also additional coking capacity added to the market with new cokers of Repsol in Spain (+86,000 bbl/d), Port Arthur refinery of Total (+50,000 bbl/d), Minatitlan refinery in Mexico (56,000 bbl/d), and Araucaria refinery in Brasil (30,000 bbl/d). Additionally, the Wood River refinery capacity in Delaware was increased 50,000 bbl/d and the Valeros´ Aruba´s refinery (235,000 bbl/d) was reactivated.

- In the third quarter of 2011, OPEC production increased from 29.2 million bbl/d to 29.9 million bbl/d in second quarter of 2011. This increment was led by Saudi Arabia and was not enough to replace in quality and quantity the shutdown of 1.6 million bbl/d of light sweet Libyan crude.

As a consequence, Latin American and USGC crude prices increased their values vs. WTI. For example, Maya crude oil was traded at an average of WTI + $8.9/bbl vs. WTI + $1.0/bbl in the second quarter.

Crude Oil and Gas sales

- In the third quarter of 2011, the Company exported seven Suezmax cargoes and 25 small parcels of crude oil, 84% Castilla blend crude (6,886,435 bbl), 8% Vasconia blend crude (679,982 bbl), and 8% Rubiales 12.5º API (627,813 bbl), representing a total volume of 8.2 million bbl during the third quarter period.

- The average realized oil price for Castilla blend crude oil during the third quarter of 2011 was $93.97/bbl, higher by 39% than the $67.44/bbl realized in the third quarter of 2010. The average differential vs. WTI NYMEX improved $14.85/bbl during the third quarter of 2011 vs. the third quarter of 2010. In this period the Company exported seven cargos of Castilla blend crude oil, four delivered to the US Gulf Coast, one to the Caribbean, one to Europe and one to Asia. Additionally, the Company sold mainly to the United States, eighteen small parcels through other exporters of Vasconia blend crude oil at an average price of $99.31/bbl.

- During the third quarter of 2011, the Company maintained its flexible commercial strategy by selling 111,289 bbl of Rubiales 12.5°API in the Colombian domestic market vs. 67,930 bbl in the previous quarter. In this period, the Company sold 627,813 bbl in seven small cargoes of 12.5°API crude oil trucked from the Rubiales field to the Atlantic Oil Terminal in Barranquilla, at an average price of $97.37/bbl, taking advantage of the strengthening of fuel oil prices. These seven cargoes were delivered to the Caribbean and the US Gulf Coast.

- For the purpose of securing diluents for Rubiales crude oil, the Company continued local purchases of light crude oils (37°API average) in the eastern Llanos (10,687 bbl/d average vs. 9,780 bbl/d average in the third quarter of 2010), supplemented with 82°API natural gasoline (2,755 bbl/d average).

- During the third quarter of 2011, the volume of natural gas sold to the local market increased to 63.3 MMscf/d, from a volume of 58 MMscf/d during the same period in 2010 (a 9% increase). These sales were mainly from La Creciente field, at an average price of $6.50/MMbtu, representing a premium of 23% over the average Maximum Regulated Price (MRP) of $5.29 /MMbtu, and 58% over the Henry Hub natural gas prices during the same period. Natural gas from La Creciente field was sold mainly to power generators located in Cartagena and Barranquilla.

- The combined realized oil and gas price for the Company for the third quarter of 2011 was $88.66/boe, higher by 42% than the $62.32/boe realized in the same period of 2010.

Average benchmark crude oil and natural gas prices for the third quarter ended September 30, 2011 were as follows:***

	3Q		
Average Crude Oil and Gas Prices	2011 ($/bbl)	2010 ($/bbl)	°API
Domestic Market	$97.71	63.56	12.5
WTI NYMEX (Weighted Average of PRE Cargoes)	$88.65	76.26	38
Vasconia (Weighted Average of PRE Cargoes and Parcels) [1]	$99.31	74.75	24
Castilla (Weighted Average of 9 Cargoes PRE) [2]	$93.97	67.44	19
Rubiales Export. 12.5º (Weighted Average of PRE Cargoes) (:	$97.37	N/A	12.5
Combined Realized International Oil Sales Price	**$94.67**	**68.15**	**N/A**
PRE Natural Gas Sales ($/MBTU)	**$6.50**	**$ 4.82**	**N/A**
Regulated Gas Price ($/MBTU)	**$3.96**	**$ 5.29**	
Combined Realized Oil and Gas Sales Price	**$88.66**	**62.32**	**N/A**
Regulated Gas Price ($/mmbtu)	$3.96	5.29	
WTI NYMEX ($/bbl)	$89.54	$76.21	
Henry Hub average Natural Gas Price ($/mmbtu)	$4.35	$4.28	
BRENT ($/bbl)	$112.09	$76.96	

(1) Weighted average price of eighteen parcels of Vasconia crude oil through third parties
(2) Weighted average price of seven Castilla crude oil cargoes

(3) Weighted average price of seven Rubiales (12.5°API) small cargoes
(4) The domestic natural gas sales price is referenced to MRP for gas produced in La Guajira field. The MRP is modified every six months based on the previous half-year variation of the US Gulf Coast Residual Fuel No.6 1.0% sulphur, Platts.

Transport of Hydrocarbons

- The Company transported 120,172 bbl/d through the different pipelines and trucking systems, including 13,542 bbl/d of diluents; 8,780 bbl/d of third party crude oil through the Guaduas Facility; 79,897 bbl/d was transported via ODL-Ocensa pipeline system 33% over the Company transportation capacity which represents savings of $31 million and 15,632 bbl/d through the ODC pipeline, representing savings of $5.8 million.
- Pipeline use represents a savings of around $17/bbl in transportation costs for the Company compared to truck transportation.
- 14,204 bbl/d was transported by truck, of which 5,137 bbl/d were transported to Guaduas-ODC pipeline system and 9,067 bbl/d to other destinations. The Company completed 9,666 truck deliveries without accidents.
- The Guaduas Facility handled and transported 24,493 bbl/d of crude oil from third parties, generating an operational profit of $2.27/bbl for the Company, totaling $5.1 million for the period, without operational or environmental incidents.

6. Project Status

STAR Project in Quifa

In March 2011, Pacific Rubiales and Ecopetrol agreed to advance with the STAR (Synchronized Thermal Additional Recovery) project in the Quifa SW field as a preliminary step to expanding the technology in the future. The project will make full utilization of all production facilities and infrastructure already acquired for the 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. STAR is a technology based on in situ combustion concepts, developed by Pacific Rubiales to increase the reserves in some heavy oil reservoirs. The synchronizing integrated model, developed by Pacific Rubiales to ensure the identification and control of the combustion front, is s key parameter in this kind of process and is unique in the oil and gas industry.

The pilot area has been selected and nine wells have been designated using a nine pattern spot inverted in a 25 acre area located close to the Quifa 38 and Quifa 8 clusters. After completing geological and reservoir modeling, eight synchronizing producing-observing wells and one injector well were identified and designed. The drilling program started using two drilling rigs and as of October 30, 2011 one of the wells has been put on production successfully.

In addition, reservoir numerical simulations have been done using the updated geological and reservoir model and kinetic reactions equations available for the Rubiales field. Results corroborated the feasibility of carrying out the pilot test in Quifa, and the additional recovery factors were calculated at over 40% of the OOIP suggesting that the ISC process and the STAR technology may increase reserves by over 1 MMbls in two years, the estimated time period of the project. This incremental recovery factor would be more than double the reserves exploited under primary conditions in the area involved.

As of the date hereof, major equipment is already installed and connected, including production manifold, production and tests fluid separators, chillers, major and small electrical generators, flow gauges and a Strafford plant for handling acid gas. The rest of the production infrastructure, such as dehydration system and production tanks, will be installed at the end of the first quarter of 2012.

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 and Colombia itself.

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 Llanomulsion 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 third quarter of 2011, the commissioning process for facilities of manufacturing Llanomulsion in CPF-1 was completed. Coordination between Meta, ODL, OCENSA and the ICP continue. The industrial test is intended to be performed in the first quarter of 2012 when the adjustments of the facilities for the 40,000 bbl test and an operational window for ODL and OCENSA is available. In the meantime, design parameters for breaking the emulsion, engineering and construction will be developed.

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 in 2009 on schedule at a total cost of $558 million. Since October 1, 2009, a total of 92 million 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 increased storage capacity at the Rubiales Pumping Station. As of September 30, 2011 the expansion of the Rubiales Pumping Station was 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 also was completed, bringing the new pumping capacity of ODL to 240,000 bbl/d. The capacity continues to expand and it is expected to reach 340,000 bbl/d by the end of 2011.

During the third quarter of 2011, the pipeline system pumped a total of 19,674,757 bbl and from this volume, 7,260,377 bbl corresponded to the Company's crude oil. On September 10, 2011, a pumping record of 262,227 bbl/d was achieved. This record was the result of the new facilities built as part of the expansion project.

With the intention of increasing operating capacity and reducing dependence on truck transportation of diluents, ODL has conducted a feasibility study for a heated oil pipeline. The results show the possibility to use mature technologies as direct fired heaters, thermal oil heating and electric process heaters. Conceptual engineering will be carried out early next year.

Finally, during this third quarter, design of new facilities in the Cusiana Station for diluting 15° API crude was completed. Construction will commence in the next quarter. When completed, this will significantly reduce transportation costs of diluent to the field.

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 Colombia´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 $162 million, of which up to 70% is expected to be project financed.

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

- Verified 100% of selected location for towers.
- Civil design for all towers.
- 33% of aluminum conductors were shipped to the storage areas.
- Completed fabrication of 50% of "suspension towers".
- 86% of right of ways have been negotiated.

- The Environmental Agency requested additional information regarding the environmental study, which was submitted on July 5th. The environmental license is expected to be issued in the fourth quarter. Construction will start as soon as this permit is granted.
- Financing terms have already been agreed upon with two local banks.

Oleoducto Bicentenario – Bicentennial Pipeline (“OBC”)

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 field 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 $1.2 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. Construction of Phase I has started and it is expected to be operational by the second quarter of 2012.

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

- The environmental license was approved on July 28, 2011.
- 100% of right of ways have been duly negotiated.
- 100% of the pipe and construction equipment are in place.
- The project has been socialized with the community.
- The contract for early pumping units in the Araguaney station was granted on September 20.

As of the date hereof, 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 have been estimated at $1.6 billion, which will bring pumping capacity in the OBC pipeline to 240,000 bbl/d.

7. Capital Expenditures

Capital expenditures during the quarter ended September 30, 2011 totaled a net amount of $276.7 million (2010 - $200 million), of which $124.9 million was invested in the expansion and construction of production infrastructure; $64.5 million went into exploration activites including seismic, aerogravimetry, aeromagnetometry and drilling; $52.9 million were invested in production activities; and $34.4 million were invested in other projects including STAR. Details on the capital expenditure program as of September 30, 2011 are as follows:

	Net Capital Expenditures (Thousands of US$)			
	Q3		Year to Date	
	2011	2010	2011	2010
Production facilities	124,936	131,775	295,290	243,146
Exploration drilling including seismic acquisition (*)	64,487	23,819	223,238	68,108
Development drilling	52,903	43,488	158,917	103,571
Other projects (STAR, Llanomulsion, Gas export, PEL)	34,402	991	68,478	1,816
Total Capital Expenditures	**276,728**	**200,073**	**745,923**	**416,641**

(*) Includes the exploration investment in Maurel et Prom in certain blocks in Colombia

8. Proved and Probable Oil and Gas Reserves

On October 3, 2011 the Company announced that it has received independent reserves evaluation reports for the Rubiales-Piriri, Quifa and Sabanero[1] Blocks, located in the Llanos Basin, Colombia. As a result of these reports, the Company's net proved and probable reserves (2P) have grown to a total of 350 MMboe as of the evaluation dates, an increase of 15.2% (without deducting production for the period) when compared to the reserves reports dated February 28, 2011 (effective December 31, 2010); or an increase of 10.5% if compared against the total reserves additions (after deducting production for the period). As of September 2011, the total proved and probable oil equivalent reserves of the Company were 411.92 million bbl gross (before royalties) or 341.73 million bbl net to the Company (after deducting the third quarter 2011 production). Details are as follows:

	2P Reserves									Oil Equivalent		
	Condensate, Light & Medium Oil			Heavy Oil			Associated & Non associated Gas					
	100%	Gross	Net	100%	Gross	Net	100%	Gross	Net	100%	Gross	Net
	(MMbbl)	(MMbbl)	(MMbbl)	(MMbbl)	(MMbbl)	(MMbbl)	BCF	BCF	BCF	(MMboe)	(MMboe)	(MMboe)
At Feb. 28/2011	7.98	3.07	2.88	611.83	266.87	224.76	544.54	543.61	506.21	715.34	365.31	316.45
Discoveries and Revision Reserves June 30,2011	-	-	-	47.97	58.75	35.55	-	-	-	47.97	58.75	35.55
Production @ June 30/2011	0.74	0.23	0.20	34.27	15.31	12.68	22.27	13.50	11.77	38.91	17.91	14.95
Total Reserves at June 30, 2011	**7.25**	**2.84**	**2.68**	**659.80**	**325.62**	**260.31**	**522.27**	**530.11**	**494.44**	**758.67**	**421.46**	**349.73**
Discoveries and Revision Reserves September 30,2011	-	-	-	-	-	-	-	-	-	-	-	-
Production July 1 to September 30/2011 (1)	0.32	0.09	0.08	18.71	8.42	6.90	5.85	5.85	5.85	20.06	9.54	8.00
Total Reserves at September 30, 2011	**6.93**	**2.75**	**2.60**	**641.08**	**317.20**	**253.41**	**516.42**	**524.26**	**488.59**	**738.61**	**411.92**	**341.73**

(1) 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.

The reserves reports for the Rubiales-Piriri and for the Quifa Southwest Field were carried out by RPS Energy ("**RPS**") as at June 30, 2011, while the reserves report for the Quifa North and Sabanero Blocks was prepared by Petrotech Engineering Ltd. ("**Petrotech**") as at September 15, 2011.

Oil equivalent is expressed in thousands of barrels (Mboe). Gas volumes are expressed in billion cubic feet (Bcf) 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 National Instrument 51-101 *Standards of Disclosure for Oil and Gas Activities*.

9. Resource Evaluation

On October 21, 2011, the Company announced the result of independent resource assessment reports for the Company's exploration blocks in Colombia, Peru and Guatemala. As a result of these resource reports, a total best estimate ("**P50**") of 398.65 MMboe of Prospective Resources (Prospects), 2,375.07 MMboe of Prospective Resources (Leads), 3.73 MMboe of Contingent Resources was presented for a Total Resources of 2,777.45 MMboe.

The applicable resource assessment report was prepared by Petrotech using an effective date of June 30, 2011 with a view to estimating the potential undiscovered oil and gas resources in the 25 exploration blocks in which the Company holds interests, for a total of 4,960,651 hectares. The resource assessment reports include 21 of the Company's 34 blocks in Colombia; three blocks located in the Maranon and Ucayali Basins of Peru and one block in Guatemala.

Country	Basin	Number of Blocks	Number of Opport.	100% Prospective Resource			Company´s share of the Prospective Resources		
				LOW MMBoe	BEST MMBoe	HIGH MMBoe	LOW MMBoe	BEST MMBoe	HIGH MMBoe
Colombia	LLANOS	9	49	232.7	1,364.9	4,511.8	131.4	753.8	2,459.2
	LMV & CR	6	18	209.6	744.0	2,407.6	187.8	671.2	2,207.6
	UMV & MMV	2	2	11.1	35.9	90.9	3.2	9.5	23.3
	PUTUMAYO	4	11	221.0	664.0	2,041.6	164.3	488.4	1,496.8
Peru	UCAYALI	2	7	282.1	1,009.3	3,394.3	163.7	660.6	2,463.5
	MARAÑON	1	1	38.3	254.6	1,104.8	21.1	140.0	607.6
Guatemala	AMATIQUE	1	1	21.2	95.7	311.8	11.7	52.7	171.5
Total Resources		**25**	**89**	**1,016.0**	**4,168.4**	**13,862.8**	**683.2**	**2,776.2**	**9,429.5**

Notes:

(1) Numbers may not add due to rounding up.

(2) BOE conversion is 5.7 Mcf per barrel using the Colombian standard

10. Discussion of 2011 Third Quarter Financial Results

Revenues

	Q3	
	2011	2010
Net crude oil and gas sales	828,285	408,534
$ per boe oil and gas	88.66	62.32

Revenue during the third quarter of 2011 totaled $828.3 million, or $88.66 per boe (2010 - $408.5 million, or $62.32 per boe), an increase of 103% in comparison to the same period of 2010. Net sales continued to grow mainly due to the 52% increase in production resulting from the construction of facilities at the Rubiales, Quifa and La Creciente fields, coupled with better realized oil and gas prices throughout the third quarter of 2011 as explained in the table below.

	Q3			
	2011	**2010**	**Difference**	**% Change**
Total of boe sold (Mboe)	9,343	6,556	2,787	43%
Avg. Combined Price - oil & gas and trading ($/bbl)	88.66	62.32	26.34	42%
Total Revenue (000$)	828,285	408,534	419,751	103%

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

Increase due to volume	172,697	41%
Increase due to price	247,054	59%
	419,751	

Operating Costs

	Q3	
	2011	2010
Oil and Gas Operating Costs	308,612	166,472
Overlift (Underlift)	18,061	(1,238)
$ per boe Crude Oil and Gas	33.04	25.40
$ per boe Over/Underlift	1.94	(0.19)
	34.98	25.21

Operating costs for oil and gas during the third quarter of 2011 were $308.6 million (2010 - $166.5 million). Production costs per boe for the third quarter of 2011 totaled $34.98 per boe, an increase of 30% in comparison to the same period of 2010. The increase over the previous period of 2010 is primarily due to the significant increase of 32% 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 - $14.44/bbl vs 2010 – $10.94/bbl). Transport costs for the quarter also increased by 69% 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 and pipeline transport costs in Colombia during 2011, as well as the foreign exchange effect of Colombian pesos conversion to US dollars. The $34.98 per boe consists of production cost of $5.29, transportation cost of $11.08, dilution cost of $14.44, overlift of $1.94 and other costs of $2.23.

Depletion, Depreciation and Amortization

	Q3	
	2011	2010
Depletion, depreciation and amortization	149,144	100,492
$ per boe	15.96	15.33

Depletion, depreciation and amortization costs during the third quarter of 2011 were $149.1 million (2010 - $100.5 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 $1.1 billion (2010 - $0.21 billion) of future development costs that are estimated to be required to bring proved undeveloped reserves to development. Depletion, depreciation and amortization costs were reduced by 16% as compared to the second quarter 2011 due to increase in the Company´s reserves issued September 2011. See additional comments in Section 10, Proved and Probable Oil and Gas Reserves.

General and Administrative

	Q3	
	2011	2010
General and administrative costs	36,555	25,148
$ per boe	3.91	3.84

General and administrative expenses for the third quarter ended September 30, 2011 were $36.6 million (2010 - $25.1 million), and the increase is mainly attributable to the net effect of:

- The significant increase in operations that resulted in hiring of new personnel and adjustment of salaries according to market standards. The number of direct and indirect employees in the third quarter of 2011 increased 35.3% to a total of 1,453 compared to 1,074 in the same period in 2010.
- The 6.4% depreciation 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 ($1.4 million in the third quarter of 2011), due to the anticipated relocation of offices to a new building in Bogota, Colombia.
- A lower hedge effect in the G&A by $3.2 million.
- A reimbursement from Ecopetrol for $6.2 million for overhead expenses incurred in previous periods.

Share-Based Compensation

	Q3	
	2011	2010
Share-based compensation	1,075	652
$ per boe	0.12	0.10

Share-based compensation was $1.08 million as a result of the granting of 200,000 (2010 - 0.6 million) fully vested options in the third quarter of 2011 compared to $0.65 million in the previous year. The increase is due to the number of options granted. All stock options outstanding as of September 30, 2011 are completely vested and exercisable and the fair values are calculated using the Black-Scholes option pricing model.

Foreign Exchange

	Q3	
	2011	2010
Foreign exchange (loss) gain	(44,271)	20,366
$ per boe	(4.74)	3.11

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 third quarter is primarily due to the appreciation of the Colombian pesos against the US dollar. The foreign exchange loss was also impacted by the US denominated debt held in Canada. Foreign exchange gains or losses primarily resulted from the translation of monetary assets or liabilities which are denominated in Colombian peso.

Finance Cost

	Q3	
	2011	2010
Interest expense	24,038	21,572
$ per boe	2.57	3.29

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 third quarter of 2011, interest expense totaled $24 million compared to $21.6 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 unused portion of the Company's Revolving Credit Facility. As of the date hereof, the Company has not drawn down on the Revolving Credit Facility. No new long-term debt was entered into during the third quarter of 2011.

Income Tax Expense

	Q3	
	2011	2010
Current income tax	108,389	35,555
Deferred income tax	18,538	(45,267)
Total	126,927	(9,712)

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 previously available on qualified capital expenditures, starting 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 has recognized the special tax benefit on qualified expenditures incurred in 2011.

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

Current income tax represents the estimated cash income taxes payable for the period. Current income tax increased to $108.4 million from $35.6 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)

	Q3	
	2011	2010
Net earnings (loss)	193,720	113,152
$ per boe	20.73	17.26

Net earnings for the three months ended September 30, 2011 totaled $193.7 million (2010 - $113.2 million). The Company´s third quarter 2011 financial results were impacted by a number of non-cash items totaling $17.7 million. These non-cash items are mainly related to unrealized mark-to-market gains on derivatives of $63 million, share-based compensation of $1 million, and foreign exchange loss of $44.3 million. These non-cash items may or may not materialize in future periods. Excluding these items, the Company's adjusted net earnings were $176 million, or $0.65 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 September 30, 2011 totaled $305.5 million. This increase is primarily attributable to the 45% increase in the combined net back in the third quarter of 2011 as compared to the same period in 2010 ($53.68 per boe in the third quarter of 2011 versus $37.11 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 $62.32 per boe in 2010 to $88.66 per boe in 2011.

	Three Months Ended Sept 30		Nine Months Ended Sept 30	
	2011	2010	2011	2010
Cash flow from operations	305,451	227,000	741,527	586,496
$ per share, basic	1.13	0.45	2.75	2.24

Financial Position

<u>EBITDA</u>

EBITDA during the three months ended September 30, 2011 totaled $465 million, which represents a significant increase of 113% compared to the third quarter 2010 EBITDA of $218.1 million; the increase is attributable to increased revenue mainly generated from international sales (87.7%); EBITDA from gas and domestic sales contributed 11% and 1.3%, respectively. Third quarter 2011 EBITDA represents a 56.1% margin in comparison to total revenues for the period (September 30, 2010 – 53.4% margin); the higher margin can be attributed to higher operating netback per boe in 2011. EBITDA for the nine months of 2011 totaled $1.4 billion, higher by 114% as compared to the same period of 2010.

<u>Debt</u>

On October 25, 2011 the Company provided notice to all holders of the Debenture an incentive to convert their Debentures at the current conversion rate plus an additional number of the Company's common shares (together, the "**Incentive Conversion Rate**") for a temporary period commencing November 9, 2011 and expiring at 5:00 p.m. (Toronto time) on November 29, 2011 (the "**Early Conversion Period**").

Debenture holders who choose to convert their Debentures during the Early Conversion Period will, pursuant to the Incentive Conversion Rate, receive: (i) all of the common shares contractually due under the current conversion rate of 77.9359 Common Shares per C$1,000 face value of the debentures; (ii) an additional number of common shares (the "**Additional Common Shares**") with value equal to C$200 per C$1,000 face value of the debentures comprised of a "make whole" payment representing the coupon to maturity and an incentive for converting early. The Company shall calculate the Additional Common Shares based on the simple average of the daily volume weighted average trading price of the common shares on the TSX commencing on Thursday October 27, 2011 up to and including Friday November 4, 2011. Holders who convert their Debentures during the Early Conversion Period will be entitled to receive accrued and unpaid interest up to and including the date that is one day prior to the conversion date, payable in cash. Debenture holders who do not convert early during the Early Conversion Period will not be entitled to the benefit of the Incentive Conversion Rate and will not receive the Additional Common Shares. The value of the incentive, once determined, will be expensed in the consolidated statements of income at the time of conversion.

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.

As of September 30, 2011, the Company had issued standby letters of credit for operational and exploration commitments for a total of $216 million (September 30, 2010 – $262.12 million). Most of these bank guarantees are related to light oil purchases and exploration commitments.

Securities

During the three months ended September 30, 2011, no Debentures were converted into common shares in the capital of the Company.

On September 8, 2011, the Company announced a cash dividend in the aggregate of $25 million, or $0.093 per common share. The dividend was paid on or about September 30, 2011 to shareholders of record as of September 20, 2011.

Outstanding Share Data

Common Shares

As at September 30, 2011, 271,631,454 common shares were issued and outstanding.

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

Stock Options and Warrants

As at September 30, 2011, 14,450 warrants to acquire an equal number of common shares were outstanding and exercisable and 22,434,510 stock options were outstanding, of which all were exercisable.

Liquidity and Capital Resources

Liquidity

Funds provided by operating activities for the quarter ended September 30, 2011 totaled $305.5 million (2010 – $227 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 September 30, 2011, the Company had working capital of $349.6 million, mainly comprised of $323.3 million of cash and cash equivalents, $709.3 million of account receivables, $198.3 million of inventory, $9.1 million of income tax receivable, $1.1 million of prepaid expenses, $678.6 million of accounts payable and accrued liabilities, $205.1 million of income tax payable, and $0.3 million of current liabilities and $7.5 million of finance lease obligations.

As at September 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 6), 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:

Assets as at September 30, 2011

Type of Instrm.	Term	Volume (bbl)	Floor/ceiling or strike price ($/bbl)	Benchmark		Fair value
Zero cost collars	January 2012 to December 2012	4,631,400	80/120 - 121	WTI		44,173
Put option	July 2011 to December 2011	3,210,000	70-75	WTI		7,443
	Total				$	51,616
	Short-term					40,414
	Long-term					11,202
	Total				$	51,616

Liabilities as at September 30, 2011

Type of Instrm.	Term	Volume (bbl)	Floor/ceiling or strike price ($/bbl)	Benchmark		Fair value
Call option	November 2011 to December 2012	10,160,000	109.50 -118.80	WTI		(17,001)
Sold put	August 1 - December31 2012	2,830,000	61.5 - 64	WTI		(28,040)
	Total				**$**	**(45,041)**
	Short-term					(9,227)
	Long-term					(35,814)
	Total				**$**	**(45,041)**

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 nine months ended September 30, 2011, the Company recorded a gain of $63 million and $55.3 million, respectively (2010 – loss of $10.6 million and $0.5 million) on commodity price risk management contracts in net earnings. Included in these amounts were $65.6 million and $60.2 million of unrealized gains (2010 – $9.5 million in unrealized loss and $9.2 million in unrealized gains) representing the change in the fair value of the contracts, and $2.6 million and $4.9 million of realized losses (2010 - $1.1 million and $9.6 million) resulting from premiums paid.

If the forward WTI crude oil price estimated at September 30, 2011 had been $1/bbl higher or lower, the unrealized gain or loss on these contracts would change by approximately $1.9 million (2010 – $1.5 million).

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 September 30, 2011

Instrument	Term	Notional amount		Floor-ceiling (COP/$)	Fair value	
Currency collar	October to December 2011	$	135,000	1860 - 1930	$	(2,606)
Currency collar	January to December 2012		650,400	1805 - 1975		(34,646)
Currency collar	January to December 2013		120,000	1870 - 1930		(6,932)
		$	905,400		$	(44,184)

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 nine months ended September 30, 2011, $24 million and $3.9 million of unrealized losses respectively (2010 - $11.7 million and $21.7 million of unrealized gains) were recorded in other comprehensive income. For the same periods, $4.8 million and $12.4 million respectively of unrealized gains (2010 - $10.5 million and $12.2 million) that were previously recorded in other comprehensive income were transferred to production and operating costs when the gains became realized. The ineffective portion of the change in the fair value of the currency hedges is recorded in foreign exchange gains or losses in the period that they arise. During the three and nine months ended September 30, 2011, $36.5 million and $41.4 million (2010 - $4.7 million and $5.7 million) of ineffectiveness was recorded as unrealized foreign exchange loss.

The Company has U.S. dollar denominated senior notes with an aggregate principle of $450 million outstanding as at September 30, 2011. The carrying amount of the senior notes is revalued against the Canadian dollar each period end at the closing exchange rate with the unrealized foreign exchange gain or loss recorded in net earnings. Based on the debt balance and foreign exchange rates as at September 30, 2011, a 10% depreciation or appreciation of the U.S. dollar against the Canadian dollar would result in a $39.9 million (2010 - $39.5 million) increase or decrease in the Company's net earnings.

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)
	Q3	Q2	Q1	Q4	Q3	Q2	Q1	Q4 (Restated (2))
Financials:								
Net sales	$ 828,285	$ 957,509	$ 583,549	$ 516,730	$ 408,534	$ 356,848	$ 379,431	$ 211,650
Net earnings (loss) for the period	193,720	349,375	(69,593)	61,326	113,152	14,438	76,127	3,218
Earnings (loss) per share								
- basic	$ 0.72	$ 1.30	$ (0.26)	$ 0.23	$ 0.43	$ 0.05	$ 0.30	$ 0.02
- diluted	$ 0.68	$ 1.20	$ (0.26)	$ 0.22	$ 0.41	$ 0.05	$ 0.28	$ 0.02

(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 for the three and nine months ended September 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 IFRS adoption 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 of September 30, 2010

	Sept 30, 2010 Cdn GAAP	Adjustment IFRS	Sept 30, 2010 IFRS
Current assets	$ 1,003,620	(13,079)	990,541
Non-current assets	2,557,063	103,452	2,660,515
Total assets	**$ 3,560,683**	**90,373**	**3,651,056**
Current liabilities	526,144	(13,707)	512,437
Non-current liabilities	1,080,216	(68,381)	1,011,835
Total liabilities	**$ 1,606,360**	**(82,088)**	**1,524,272**
Shareholders' equity	1,954,323	172,461	2,126,784
Total Liabilities and shareholders' equity	**$ 3,560,683**	**90,373**	**3,651,056**

Reconciliation of Consolidated Statement of Financial Position as of 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 September 30, 2010

	Sept 30, 2010 Cdn GAAP	Adjustment IFRS	Sept 30, 2010 IFRS
Total revenue	$ 405,421	$ 3,113	$ 408,534
Total expense	311,353	(6,259)	305,094
Income before taxes	**94,068**	**9,372**	**103,440**
Income taxes	(61,212)	52,874	9,712
Net income	**$ 32,856**	**$ 62,246**	**$ 113,152**

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 $3.2 million for the three months ended September 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 five year lease agreement with Blue Pacific Assets Corp. ("**Blue Pacific**") for administrative office space in one of the Company's seven Bogota, Colombia locations. Monthly rent expense of $57 for this location 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 second quarter of 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 new office space consolidates each of the Company's prior seven locations in Bogota and provides one office for all of the Company's employees in Bogota. The Company expects to receive increased efficiencies by having all employees in one office space. The increased size of the office space is attributable to the fact the Company had 277 employees in Bogota in 2007 and currently has over 1589 employees in Bogota.

   The Company also has accounts receivable of $1.8 million from Blue Pacific as at September 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 $nil and $1.1 million to Blue Pacific during the three and nine months ended September 30, 2011 respectively (2010 - $nil and $0.5 million) for air transportation services.

b) As at September 30, 2011, the Company had trade accounts receivable of $5.0 million (December 31, 2010 - $1.7 million) from Proelectrica, in which the Company has a 20.2% indirect interest and which is 31.49% owned by Blue Pacific. The Company's and Blue Pacific's indirect interests are held through Pacific Power. Revenue from Proelectrica in the normal course of the Company's business was $7.1 million and $17.4 million for the three and nine months ended September 30, 2011 respectively (2010 - $2.3 million and $12.5 million).

c) During the three and nine months ended September 30, 2011, the Company paid $12.0 million and $36.3 million respectively (2010 - $10.9 million and $30.5 million) to Transmeta in crude oil transportation costs. In addition the Company has accounts receivable of $3.4 million (December 31, 2010 - $4.1 million) from Transmeta as at September 30, 2011. Transmeta is controlled by a director of the Company.

d) Loans receivable in the aggregate amount of $0.8 million (December 31, 2010 - $0.3 million) are due from three management directors and three officers of the Company as at September 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 to Colombia as part of the Company's compensation program for all employees.

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 nine months ended September 30, 2011, the Company paid $1.2 million and $4.4 million respectively (2010 - $1.7 million and $4.1 million) in fees as set out under the transportation agreements.

f) The Company received $nil and $1.6 million from ODL during the three and nine months ended September 30, 2011 respectively (2010 – $1.6 million and $4.8 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 September 30, 2011 (December 31, 2010 – $3.1 million).

g) In July 2011, the Company acquired an additional equity interest in Pacific Infrastructure Inc. ("**Pacific Infrastructure**") from an unrelated party for cash consideration of $4.4 million. Four directors and two officers of the Company are directors or officers of Pacific Infrastructure.

h) In July 2011, the Company acquired an additional 2.5% equity interest in Pacific Power Generation Corp. (formerly Ronter Inc.) from an unrelated party for cash consideration of $0.8 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 ("I**CFR**").

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

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

- Evaluation of design and operating effectiveness of internal controls over financial reporting and disclosure controls and procedures as promulgated by National Instrument 52-109 ("**NI 52-109**") as issued by the Canadian Securities Administrator ("**CSA**")
- Effectiveness and efficiency of operations,
- Reliability of internal and external reporting, and
- Compliance with applicable laws and regulations.

During the quarter ended September 30, 2011, Corporate Audit continued activities focused on identifying, evaluating, and addressing critical and material risks for the organization. Following are some of the most significant risks reviewed, as well as the actions initiated by management to mitigate them:

- Regulatory compliance: Some of the activities included the review and update of the governance programs which included the Business Code of Ethics and Corruption of Foreign Public Officials Act ("**CFPOA**"), anti-money laundering, and data security.

- Credit and liquidity strains: The audit review was focused on client risk rating process and strategies, improving the automated environment to gain greater control of processing.

- Potential increased fraud risk: Audit reviews were performed to reduce this risk included employee fraud awareness training to help maintaining fraud-resistance, fraud risk assessment within key areas and used the results to prioritized fraud detection efforts toward key current fraud risks, and review of segregation of duties controls and other fraud controls.

- Data security and privacy protection: The audit review was focused on the implementation of tools to protect the access to the network and the implementation of application securities, the use of tools to continuous auditing and monitoring, and the strengthening of control IT environment according with the standards.

- Also, evaluation of the effectiveness of internal controls, encompassed within the requirements of 52-109 issued by the CSA, over the design and operating effectiveness of the ICFR (Internal Controls Over Financial Reporting). During this quarter a evaluation of operating effectiveness of the ICFR for 534 controls over 32 processes.

  From this evaluation the Company concluded that there are no material weaknesses or significant deficiencies in the design and effectiveness of the controls evaluated. The identified opportunities to improve the ICFR are in the following main areas:
  - Administration of contracts with suppliers
  - Project management documentation and commissioning
  - Compliance with the Company´s maintenance equipment program

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

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

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 field production to between 250,000 and 260,000 boe/d by the end of 2011. The Company will continue pursuing its strategy of production growth from its producing assets, but also continuing with exploration activity to incorporate new reserves in the future.

The Company's exploration activities will continue in 2011 and includes the drilling of 30 additional wells, the acquisition of 739 km of 2D seismic and 802 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 third quarter 2011 as compared with the third quarter of 2010:

	Three Months Ended Sep-30		Nine Months Ended Sep-30	
	2011	2010	2011	2010
Cash flow from operating activities	305,451	227,000	741,527	586,496
Changes in non-cash working capital	(44,479)	65,572	(275,312)	127,298
Funds flow from operations	349,930	161,428	1,016,839	459,198

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

	Three Months Ended Sep 30		Nine Months Ended Sep 30	
	2011	2010	2011	2010
Net earnings	193,720	113,152	473,502	203,717
Adjustments to net earnings				
Income taxes expense	126,927	(9,712)	258,592	62,089
Foreign exchange loss (gain)	44,271	(20,366)	41,841	(25,650)
Finance cost	24,038	21,572	70,968	55,868
Loss (gain) on risk management contracts	(63,027)	10,639	(55,289)	478
Loss (gain) from equity investment	(12,859)	215	(1,770)	(860)
Other expense (income)	1,768	986	4,838	1,308
Share-based compensation	1,075	652	48,467	73,327
Equity tax	-	522	68,446	1,566
Depletion, depreciation and amortization	149,144	100,492	476,328	276,860
EBITDA	465,057	218,152	1,385,923	648,703

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.

Certain financial information already filed under Canadian GAAP for the third quarter of 2010 may vary with information presented in this period, due to adjustments in the first time adoption of IFRS as discussed in Section 16 – New Accounting Pronouncements.

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

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
	include millions MMbbl
Mboe	thousand barrels of oil equivalent
	include millions (MMboe)
Mcf/d	thousand cubic feet per day
MMcf/d	Million cubic feet per day
Mcf	thousand cubic feet
MD	Measured depth
OOIP	Original oil in plays
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