



Management's Discussion and Analysis
Three and nine months ended September 30, 2011 and 2010

In accordance with National Instrument 51-102 *CONTINUOUS DISCLOSURE OBLIGATIONS*, the Company discloses that its auditors have not reviewed the unaudited financial Statements and MD&A for the periods ended September 30, 2011 and 2010.

MANAGEMENT'S DISCUSSION AND ANALYSIS

This Management's Discussion and Analysis ("MD&A") has been prepared by management as of November 24, 2011 and reviewed and approved by the Board of Directors of Forent Energy Ltd. ("Forent" or the "Company"). The MD&A reviews the operational results of the Company with disclosure of oil and gas activities in accordance with Canadian Securities Regulators National Instrument 51-101 Standards of Disclosure for Oil and Gas Activities ("NI 51-101") and a review of financial results of the Company based on International Financial Reporting Standards ("IFRS"), which are the new accounting principles generally accepted in Canada ("GAAP"). Its focus is primarily a comparison of the operational and financial performance for the three and nine months ended September 30, 2011 and 2010 and should be read in conjunction with the December 31, 2010 audited financial statements that were prepared under the previous Canadian generally accepted accounting principles ("previous GAAP") and the accompanying notes.

All financial measures presented in this MD&A are expressed in Canadian dollars unless otherwise indicated.

Forward Looking Information

Certain statements contained in this report, including statements that may contain words such as "anticipates," "can," "may," "expect," "believe or believes" and "will" and similar expressions are forward-looking statements. These statements may include, but are not limited to, future capital expenditures, future financial resources, future oil and gas well activity, outcome of specific events, and trends in the oil and gas industry. These statements are derived from certain assumptions and analyses made by the Company based on its experience and interpretation of historical trends, current conditions and expected future developments, and other factors that it believes are appropriate in the circumstances. These statements or predictions are subject to a number of known and unknown risks and uncertainties, which are discussed previously in this report that could cause actual results to differ materially from the Company's expectations. Consequently, all of the forward-looking statements made in this report are qualified by these cautionary statements and there can be no assurance that actual results or developments anticipated by the Company will be realized, or that they will have the expected consequences or effects on the Company or its business or operations. The Company assumes no obligation to update publicly any such forward-looking statements, whether as a result of new information, future events or otherwise, except as required by applicable law.

For the purpose of calculating unit costs, natural gas volumes have been converted to a barrel equivalent ("boe") using six thousand cubic feet equal to one barrel unless otherwise stated. A boe conversion ratio of 6:1 is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. This conversion conforms with national instrument NI51-101. Boe's may be misleading, particularly if used in isolation.

The terms funds from operations, funds from operations per share and operating netback are terms that do not have a standardized measuring prescribed by GAAP. Management believes that funds from operations, funds from operations per share and operating netback are useful supplemental measures as they demonstrate the Company's ability to generate the cash necessary to repay debt or fund future growth through capital investment. Investors are cautioned, however, that these measures should not be construed as an alternative to cash flow determined in accordance with GAAP as an indication of the Company's performance. Forent's method of calculating these measures may differ from other companies, and accordingly, may not be comparable to measures used by other companies. For these purposes, the Company defines funds from operations as cash provided by operations before changes in non-cash operating working capital and defines operating netback as revenue less royalties and operating expenses. The Company also presents funds from operations per share whereby amounts per share are calculated using weighted average shares outstanding consistent with the calculation of earnings per share.

Introduction and Overview of Forent Energy Ltd.

Forent Energy Ltd. is a crude oil and natural gas exploration and development company headquartered in Calgary, Alberta. The Company's operations include established oil and gas production in Alberta and Saskatchewan and the exploration for both oil and gas onshore in Nova Scotia.

Forent Energy Ltd. was incorporated under the Business Corporations Act of Alberta as a private company on April 6, 1999. Forent became a public company as a result of the reverse takeover of Seriatim Ventures Inc. a capital pool company listed on the TSX Venture Exchange, which was completed on December 18, 2008.

The Company's operational focus over the next one to two years is to continue its strategy of growth through heavy oil development drilling and focused exploration on its two core exploration areas consisting of i) the onshore Alton Block ("Alton") in Nova Scotia and ii) on its 27 section Montgomery, Alberta property ("Montgomery"). Forent has assembled a team of individuals with many years experience in both western Canada and frontier exploration, such as Nova Scotia, in order to take advantage of these opportunities.

EXECUTIVE SUMMARY & OUTLOOK

Overview of the Third Quarter 2011

The third quarter saw the Company make considerable progress on the onshore Alton Block in Nova Scotia with the acquisition, processing and interpretation of 65 km of 2D seismic data. During the third quarter the Company relinquished its interest in the Beech Hill Exploration Block (at the end of the first three year exploration term), in order to focus its efforts on the Alton Block and the Montgomery exploration opportunity in Alberta. As a junior company, management was concerned about diluting its exploration resources and decided not to make any additional spending commitments for another three years of exploration on the Beech Hill Block. Should Alton prove to be a success, the Company would consider re-applying to the government for an exploration licence at Beech Hill. The Company achieved a significant increase in funds from operations in the three months ended September 30, 2011, over the same period of 2010, with funds from operations increasing to \$151,947 from \$49,173 in the third quarter of 2010.

Alton Block, Nova Scotia

The Company's 65 km 2D seismic acquisition program was complete at the end of July. The total cost of the seismic program was under \$1 million and well within budget. During the third quarter, the data was processed, interpreted and correlated to the 2010 gravity gradiometry information. The Company was very pleased by the results of its 2D program. In September the Company initiated applications to the Nova Scotia departments of Energy and Environment in order to obtain approval to drill three exploration wells on the Alton Block. Approvals from the government of Nova Scotia were received on November 16, 2011.

During the third quarter the Company continued to dedicate resources to ensure all stakeholders understand its objectives for the Alton Block. As part of this process the Company established a community liaison committee comprised of individuals from the local community, including members of the First Nations. The community liaison committee will meet several times a year and serve as a forum for the community to build understanding, make suggestions and identify concerns regarding Forent's operations on the Alton Block. Forent staff met with members of the public in mid-October at an open house in Stewiacke, Nova Scotia to review the Company's plan for the drilling of three exploration wells later this year. The open house was an important part of the approval process with the government of Nova Scotia for the drilling of the wells. The feedback received at the open house was positive and very encouraging for our drilling program.

Onshore petroleum exploration in Nova Scotia is an industry that's in its infancy in comparison to the western Canadian sedimentary basin. Forent has taken an approach that is focused on ensuring all

stakeholders are informed and educated as to the exploration process that the Company is pursuing. Specifically, the Company has indicated that it is drilling for crude oil into the reef structures it has identified and will not need to hydraulically fracture any of the proposed wells.

Montgomery, Alberta

The Company continued its search for a partner and while we came very close to identifying one in September, negotiations were not successful. In early October a decision was made to engage Sayer Energy Advisors to assist the Company to find a partner. Sayer has prepared a marketing package and requested that bids be submitted by November 24th, 2011 after which we hope to have identified at least a couple of interested parties and initiate negotiations for a partner to drill three exploration wells in the Montgomery, Alberta project area.

Forent holds a unique exploration land position at Montgomery, where it has identified a number of drilling locations, including multi-zone, three-way structural closures of significant areal extent, as well as, a number of Second White Specs prospects, that appear similar to a very successful nearby Second White Specs well. The lands have never been explored due to lack of surface access that Forent was able to obtain late last year. During the third quarter the Company continued its program of establishing and maintaining good working relationships with the ranchers that own the surface rights where we intend to drill.

Western Canadian Operations

After several delays the Company has tied in all of its Mervin, Saskatchewan producing wells to its salt water disposal well and has now stopped all in-field trucking, resulting in reduced monthly operating costs of approximately \$70,000 and approximately \$30,000 in additional third party disposal revenues being realized. The majority of the funds required for the Mervin salt water disposal project were secured from the sale of the Company's 37.5% interest in two wells in the Provost area of Alberta. On a combined basis the company's net interest in the two wells was approximately 14 bbl/d.

Financial and operating – Third Quarter of 2011

- Oil production in the third quarter increased by 27 percent, with natural gas decreasing by 25%, compared to 2010;
- average commodity selling prices for oil, NGL's and natural gas increased by 16 percent vs. 2010;
- net oil and gas revenues increased by 14 percent to \$856,864 from \$751,568 in 2010;
- operating expenses per boe increased 32 percent to \$29.79 per boe from \$22.52 in 2010;
- corporate netbacks for the quarter increased from \$1.03 per boe in 2010 to \$4.18 per boe in 2011;
- general and administrative expenses decreased 36 percent and fell on a per boe basis by 14 percent to \$7.84 per boe; and
- the Company generated cash flow of \$151,947 in the third quarter of 2011, compared to \$49,173 in 2010.

Outlook for the balance of 2011

The Company is currently undertaking a \$3.5 million brokered financing on a best efforts basis for the private placement of 25,000,000 Common Shares to be issued on a "flow-through" basis at a price of \$0.14 per share. The Offering is scheduled to close on or about December 7, 2011 and the funds raised will be dedicated to the three well Alton drilling program scheduled to commence in mid-December.

The Company has secured a drilling rig, suitable for our requirements and have commenced our site preparation during the week of November 21st. The Company will share the costs of moving the rig to Nova Scotia and returning it to Quebec with a private company that intends to use the rig to drill one well before we embark on our program.

At Mervin, the completion of the tie-in of its salt water disposal well enables the Company to initiate a program to increase production rates from the six existing Mervin producing wells later this quarter. The production optimization was delayed due to the incremental cost of trucking water that the Company would have incurred before the wells were tied in. In addition, we understand that there is considerable demand in the immediate vicinity for salt water disposal facilities and believe that additional revenues can be achieved. Our salt water disposal well is capable of handling more than 3,000 cubic metres a day of salt water and we estimate that we might achieve additional third party salt water revenues of approximately \$30,000 per month.

As indicated previously, the Company is seeking a partner for its Montgomery, Alberta exploration opportunity and has engaged Sayer Energy Advisers to assist in identifying a partner and evaluating offers. Forent anticipates completing a multiple well farm-out in the fourth quarter of the year.

The Common shares of Forent are listed for trading on the TSX Venture Exchange under the symbol FEN.

Additional information regarding Forent is available under the Company's profile on SEDAR at www.sedar.com. Information is also accessible on the Company's website www.forentenergy.com.

Changes in Accounting Policy

As of January 1, 2011, Forent prepared its financial statements in accordance with International Financial reporting Standards ("IFRS"), including IFRS 1 – First time adoption of IFRS and International Accounting Standard 34 – Interim Financial Reporting, as issued by the International Accounting Standards Board. Previously, the Company's financial statements were prepared in accordance with Canadian Generally Accepted Accounting Principles ("Canadian GAAP"). Unless otherwise noted, 2010 comparative information has been prepared in accordance with IFRS. The adoption of IFRS has not had an impact on the Company's funds flow. The most significant areas that were impacted by the adoption of IFRS were property, plant and equipment, decommissioning liabilities, share capital treatment of flow-through shares and the deferred tax adjustments related to all of the above.

Financial Results

Production

	Three months ended September 30,			Nine months ended September 30,		
	2011	2010	Change (%)	2011	2010	Change (%)
Daily Production						
Natural gas (mcf/d)	452	604	(25)	491	625	(21)
Crude oil and NGLs (bbls/d)	147	116	27	166	57	191
Boe/d	222	216	3	248	161	54
	(%)	(%)	(%)	(%)	(%)	(%)
Production Mix						
Natural gas	34	47	(28)	33	64	(48)
Crude oil and NGLs	66	53	25	67	36	86
	100	100		100	100	

The Company's overall production for the third quarter of 2011 averaged 222 boe/d, an increase of 3% from the 216 boe/d recorded during the same period of 2010. Natural gas production decreased 25% in the third quarter of 2011 to 452 mcf/d from 604 mcf/d in the same quarter of 2010. The decrease in natural gas production was primarily a result of the production declines at the Company's Ferrybank 8-32 natural gas well, between the two periods. Crude oil and natural gas liquids ("NGLs") production increased by 27% to 147 bbls/d during the three months ended September 30, 2011 from 116 bbls/d in the same period of 2010. The Mervin, Saskatchewan heavy oil wells account for the majority of the crude oil and NGLs increase as a result of additional wells in the area coming on stream late 2010. Additionally, the Company sold its Provost, Alberta interest during the third quarter representing approximately 14 bbls/d of oil production effective June 1, 2011.

Company production volumes during the nine months ended September 30, 2011 increased 54%, averaging 248 boe/d compared to 161 boe/d in the corresponding period of 2010. Natural gas production decreased 21% to 491 mcf/d from 625 mcf/d during the nine months ended September 30, 2011 and 2010, respectively. The decrease between the two periods in natural gas production was primarily a result of the production declines at the Company's Ferrybank 8-32 natural gas well, which were partially offset by the Richdale well production that became fully on stream in 2011. Crude oil and NGLs production increased to 166 bbls/d during the nine months ended September 30, 2011, from 57 bbls/d during the same period of 2010, representing an increase of 191%. The significant increase in crude oil and NGL production was primarily the result of the Mervin, Saskatchewan heavy oil wells being brought on stream starting in May 2010 and having that incremental crude oil production in 2011.

Natural gas revenue represented 34% and 66% of the Company's total sales during the three months ended September 30, 2011 and 2010, respectively. Crude oil and NGL production increased significantly, shifting the Company's production base representing 66% of production in the third quarter of 2011, as compared to 53% in the same period of 2010. The Company's decrease in natural gas weighting to focusing on crude oil and NGL production was a strategic shift that was initiated in late 2009 in an attempt to provide higher ongoing cash flows from the higher profit margin commodity of crude oil and NGLs relative to natural gas.

Natural Gas Prices

United States natural gas prices are commonly referenced off the New York Mercantile Exchange at the Henry Hub, Louisiana ("NYMEX") index price, while Canadian natural gas prices are typically referenced to the AECO Hub in Alberta ("AECO"). Natural gas prices are primarily influenced by North American supply and demand rather than global fundamentals. In the first nine months of 2011, the AECO natural gas price averaged \$3.78/mcf compared to \$4.13/mcf in the same period of 2010. The lower natural gas prices in 2011 compared to 2010 were primarily a result of strong supply resulting from various new shale gas projects, which led to an abundant supply of natural gas throughout 2010 and into 2011.

Crude Oil Prices

Alberta crude oil prices are commonly referenced to Edmonton par pricing with adjustments being taken to reflect the quality of the actual produced crude oil. The average Edmonton par pricing for the nine months ended September 30, 2011 was \$101.31/bbl and \$76.84/bbl in the same period of 2010. The majority of Forent's crude oil production consists of heavy oil that has historically sold at a discount relative to the Edmonton par pricing. Oil prices strengthened in 2011 largely as a result of increased global demand attributable to the global economic recovery. In addition, political uncertainty positively affected prices by adding a risk premium to international prices.

Pricing

	Three months ended September 30,			Nine months ended September 30,		
	2011	2010	Change	2011	2010	Change
	(\$)	(\$)	(%)	(\$)	(\$)	(%)
Selling Prices						
Natural gas (\$/mcf)	3.70	3.86	(4)	4.05	4.18	(3)
Crude oil and NGLs (\$/bbl) ⁽¹⁾	59.22	59.13	-	64.56	62.71	3
Average weighted selling price (\$/boe)	46.69	40.33	16	51.27	37.51	37

(1) Combined crude oil and NGLs pricing may result in prices that are significantly different than those received for crude oil in isolation, due to NGLs being priced on a different basis than crude oil.

Average natural gas prices received by Forent decreased 16% in third quarter of 2011 to \$3.70/mcf from \$3.86/mcf received during the same quarter of 2010. The price received by Forent did not decline as much as the average AECO price, as a result of the Company not selling all of its gas at a monthly average AECO value. Crude oil and NGLs prices remained relatively constant at \$59.22/bbl recorded during the third quarter of 2011 as compared to \$59.13/bbl in the same quarter of 2010. There are two reasons that the oil price Forent received was fairly constant while the price of Edmonton Par crude was \$24.47 higher in 2011 than it was in 2010. The two factors were i) the widening of the discount on heavy crude in 2011 vs. 2010 and ii) Forent's average barrel of production was of heavier quality in 2011 than it was in 2010, as a result of the increase in production at Mervin. Selling prices for the nine months ended September 30, 2011 averaged \$4.05/mcf for natural gas and \$64.56/bbl for crude oil and NGLs compared to \$4.18/mcf and \$62.71/bbl, respectively, during the same nine month period of 2010. The Company's selling prices of crude oil and natural gas were relatively consistent between the periods.

Oil and Gas Revenue

	Three months ended September 30,			Nine months ended September 30,		
	2011	2010	Change	2011	2010	Change
	(\$)	(\$)	(%)	(\$)	(\$)	(%)
Revenue						
Natural gas sales	153,984	214,294	(28)	543,020	712,635	(24)
Crude oil and NGLs sales	801,069	628,712	27	2,932,694	981,298	199
Total petroleum sales	955,053	843,006	13	3,475,714	1,693,933	105
Less: Crown and freehold royalties	(98,189)	(91,438)	7	(486,607)	(211,049)	131
Net oil, NGLs and natural gas sales	856,864	751,568	14	2,989,107	1,482,884	102
Other oil and natural gas operating revenues	60,059	21,880	174	145,981	67,709	116
Total oil and natural gas revenues	916,923	773,448	19	3,135,088	1,550,593	102

The Company's total oil and gas revenue for the three months ended September 30, 2011, was \$916,923, an increase of 19% from the same period of 2010, when revenue totalled \$773,448. Gross natural gas revenues decreased 28%, to \$153,984 in the third quarter of 2011 from \$214,294 in 2010, as a result of the 25% decrease a production along with lower natural gas prices. Crude oil and NGL revenues increased 27% between the third quarters of 2011 and 2010, to \$801,069 from \$628,712, respectively, primarily as a result of production from the six heavy oil well reactivations at the Company's Mervin property in May of 2010.

During the nine months ended September 30, 2011, the Company's total oil and gas revenue increased 102% to \$3,135,088, from \$1,550,593 generated in the same period of 2010. Gross natural gas revenues decreased 24%, to \$543,020 in the nine months of 2011 from \$712,635 in 2010, as a result of the 21% decrease in production. Crude oil and NGL revenues increased 199% to \$2,932,694 during the nine months ended September 30, 2011, from \$981,298 received in the same period of 2010. The increase was primarily attributed to the reactivation of the Company's Mervin property in May of 2010.

Royalty Expense

	Three months ended September 30,			Nine months ended September 30,		
	2011	2010	Change	2011	2010	Change
	(\$)	(\$)	(%)	(\$)	(\$)	(%)
Total royalties	98,189	91,438	7	486,607	211,049	131
As a % of oil and gas sales	10%	11%	(9)	14%	12%	17
\$/boe	4.80	4.60	4	7.18	4.79	50

During the three months ended September 30, 2011, the Company's royalty expense increased 7% to \$98,189 from \$91,438 in the same period of 2010. The increase in the royalty expense was primarily due to increased crude oil production, which was offset substantially by lower natural gas revenues and additional custom processing and operating cost credits on Alberta crown royalties. In the nine months ended September 30, 2011 royalty expense increased 131% to \$486,607 from \$211,049 in the same period of the 2010, as a result of the increased production and petroleum revenues, which were partially offset by crown royalty credits as described above.

Royalties as a percentage of sales for the three months ended September 30, 2011 remained relatively consistent at 10% of oil and gas sales, which was a 9% decrease from the 10% calculated for the same period of 2010.

Operating Expenses

	Three months ended September 30,			Nine months ended September 30,		
	2011	2010	Change	2011	2010	Change
	(\$)	(\$)	(%)	(\$)	(\$)	(%)
Operating expenses	609,455	448,011	36	1,848,299	961,771	92
Operating expenses (\$/boe)	29.79	22.52	32	27.27	21.82	25

Operating expenses increased 36% to \$609,456 in the third quarter of 2011 compared to \$448,011 in same quarter of 2010. The increase in operating expenses was a related to the higher production volumes resulting from the addition of two Mervin wells coming on stream in late 2010 in conjunction with a general field production increase through equipment upgrades, along with small production increases from a number of additional Company wells. On a per boe basis, operating expenses increased 32% to \$29.79 per boe in the three months ended September 30, 2011 from \$22.52 per boe in the same period of 2010, as a result of the significant water hauling costs incurred at the Company's Mervin heavy oil property.

During the nine months ended September 30, 2011, operating costs increased 92% to \$1,848,300 from \$961,771 in the same period of 2010, reflecting the year-over-year increase in production. On a per boe

basis, operating expenses increased by 25% as a result of the significant water hauling costs incurred at the Company's Mervin heavy oil property. The Company has taken steps to significantly reduce the Mervin water hauling expenses. In November 2011 Forent completed the tie-in of the Mervin heavy oil wells to its water disposal well that is expected to realize cost savings of \$70,000 a month and result in a considerably lower operating cost per boe.

General and Administrative ("G&A") Expenses

	Three months ended September 30,			Nine months ended September 30,		
	2011	2010	Change	2011	2010	Change
	(\$)	(\$)	(%)	(\$)	(\$)	(%)
Gross expenses	186,215	275,045	(32)	924,782	876,223	6
Overhead recoveries	(25,928)	(32,739)	(21)	(79,173)	(98,911)	(20)
Total G&A expense	160,287	242,306	(34)	845,609	777,312	9
\$/boe	7.84	12.18	(36)	12.47	17.64	(26)

During the three months ended September 30, 2011, general and administrative expenses decreased 34% to \$160,287 from \$242,306 in the same period of 2010. The decrease in general and administrative expenses was a result of a reduction in professional fees consisting mainly of legal and land consulting fees as compared to same period of 2010. In the nine months ended September 30, 2011, general and administrative expenses increased 9% to \$845,609 from \$777,312 in the corresponding period of 2010. The increase between the nine month periods of September 30, 2011 and 2010 was primarily related to the additional employee and consulting expenses incurred during the first half of 2010 related to its continued exploration and development plans of the Montgomery, Alberta and Alton, Nova Scotia projects.

The overhead recoveries from partners, related to Forent operated projects, decreased 21% to \$25,928 in the three months ended September 30, 2011, compared to \$32,739 in the same period of 2010. The decrease was due to cost reductions at the Huxley property in which overhead is based upon costs incurred, thereby reducing both operating costs and overhead recoveries. Overhead recoveries from partners are earned primarily on the Huxley area wells and gas plant and gas gathering system that the Company operates, along with operated capital projects.

Stock Based Compensation

Stock-based compensation expense decreased 14% to \$54,261 in the third quarter of 2011 from \$62,967 in the same period of 2010. During the nine months ended September 30, 2011, the stock-based compensation expense increased 26% to \$217,298 from \$173,055 in the same period of 2010. The increase in stock based compensation during the nine months of 2011 was a result of 2,760,000 stock options being granted on February 4, 2011 and the additional expense related to the immediate vesting of one third of those stock options. The total number of options outstanding as at September 30, 2011 is 6,592,687 with a weighted average exercise price of \$0.26 and life of 4.01 years.

Operating Netbacks per boe

	Three months ended September 30,			Nine months ended September 30,		
	2011	2010	Change	2011	2010	Change
	(\$/boe)	(\$/boe)	(%)	(\$/boe)	(\$/boe)	(%)
Sales price	46.69	42.38	10	51.27	38.44	33
Royalties	(4.80)	(4.60)	4	(7.18)	(4.79)	50
Operating	(29.79)	(22.52)	32	(27.27)	(21.82)	25
Operating netback	12.10	15.26	(21)	16.82	11.83	42
G&A (net of non-cash items)	(7.84)	(12.18)	(36)	(12.47)	(17.64)	(29)
Interest and other (net of non-cash items)	(0.08)	(2.05)	(96)	(0.21)	(0.84)	(75)
Corporate netback (loss)	4.18	1.03	306	4.14	(6.65)	(162)

During the third quarter of 2011 the Company's operating netback decreased to \$12.10/boe from a \$15.26/boe recorded in same period of 2010. The decrease in the netback was primarily related to the significant increase in water hauling costs at Mervin between the periods, which were partially offset by the increased sales price. During the nine months ended September 30, 2011 the operating netback improved to \$16.82/boe from a netback of \$11.83/boe in the same period of 2010. The increase was attributed to the shift towards a greater proportion of oil as compared to natural gas resulting in the significant improvement in oil and gas selling prices, which was partially offset by greater operating costs and higher royalties, all on a per boe basis.

During the third quarter of 2011, the Company's corporate netback improved to \$4.81/boe from \$1.03/boe in the same period of 2010. On a corporate netback basis the Company's netback in the nine months period of September 30, 2011, increased \$4.14/boe from a negative netback of \$6.65/boe in the same period of 2010. The corporate netback improvement in the three and nine month periods was a result of increased production, a higher ratio of oil to gas, increased selling prices and a significant decrease in general and administrative costs on a per boe basis, which was offset by the higher per boe operating costs at Mervin as a result of the considerable water hauling required to produce the field.

In November 2011 the Company tied in the Mervin wells by pipeline to transport produced water to its water disposal well. Previously the Company hauled the produced water to its disposal well and approximates that \$70,000 per month will be saved as a result of the tie-in.

Depletion and Depreciation

	Three months ended September 30,			Nine months ended September 30,		
	2011	2010	Change	2011	2010	Change
	(\$)	(\$)	(%)	(\$)	(\$)	(%)
DD&A provision	312,896	452,070	(31)	1,194,927	1,191,509	-
DD&A provision (\$/boe)	15.30	22.73	(33)	17.63	27.04	(35)

The DD&A provision decreased 31% to \$312,896 in the third quarter of 2011, as compared to \$452,070 in the same period of 2010. The decrease was primarily attributed to the sale of the provost wells in the third quarter of 2011 which reduced the depletable base, in conjunction with the impairment charge recorded in the prior period that substantially increased the depletion rate in the third quarter of 2010.

During the nine months ended September 30, 2011 the DD&A provision remained relatively constant at \$1,194,927 from \$1,191,509 during the same period of 2010. When factoring in the sale of the provost properties and the impairment charge recorded in the third quarter of 2010, the depletion expense during the nine month period of 2011 would have been modestly higher than the same period of 2010, as a result of the greater production levels in 2011.

On a per boe basis, the DD&A provision decreased 33% to \$15.30/boe from \$22.73/boe in the three months ended periods of September 30, 2011 and 2010, respectively.

Income Taxes

For the three months ended September 30, 2011, there was a future income tax recovery of \$44,459 recorded in the period, compared to a recovery of \$76,303 recorded in the same period of 2010. In the nine months ended September 30, 2011 a future income tax recovery of \$151,774 was recorded, as compared to a recovery of \$232,835 in the same period of 2010. The changes in this non-cash item are due to the anticipated future tax effect of the period's activities after reconciling recorded net assets with the Company's tax pool assets at the end of each period.

As at September 30, 2011, the Company had approximately \$9.8 million in tax pools available to shelter taxable income in future years.

Funds from Operations

	Three months ended September 30,			Nine months ended September 30,		
	2011	2010	Change	2011	2010	Change
	(\$)	(\$)	(%)	(\$)	(\$)	(%)
Cash flow (used in) from operating activities (per GAAP)	(46,011)	440,833	(110)	565,997	(91,757)	(717)
Change in non-cash working capital	197,958	(391,660)	(151)	(120,154)	(116,631)	3
Funds from (used in) operations	151,947	49,173	209	445,843	(208,388)	(314)

The Company determines funds from operations as cash provided from operations before changes in non-cash operating working capital.

	Three months ended September 30,			Nine months ended September 30,		
	2011	2010	Change	2011	2010	Change
	(\$)	(\$)	(%)	(\$)	(\$)	(%)
Funds from (used in) operations	151,947	49,173	209	445,843	(208,388)	(314)
Per share – basic and diluted	-	-	-	-	-	-

Funds from operations increased to \$151,947 (\$nil per basic and diluted share) for the three months ended September 30, 2011 compared to \$49,173 (\$nil per basic and diluted share) in the comparable period of 2010. During the nine months ended September 30, 2011, the funds from operations increased to \$445,843 (\$nil per basic and diluted share) from funds used in operations of \$208,388 (\$nil per basic and diluted share) in the same period of the prior year. The improvement in the three and nine month period cash flows was primarily attributable to the greater volumes of Company production and improvement in commodity selling prices as a result of greater percentage of revenues being derived from the higher priced crude oil and natural gas liquids.

Net earnings

	Three months ended September 30,			Nine months ended September 30,		
	2011	2010	Change	2011	2010	Change
	(\$)	(\$)	(%)	(\$)	(\$)	(%)
Net loss	(540,761)	(497,473)	9	(1,203,732)	(1,687,713)	(29)
Per share – basic and diluted	-	(0.01)	(100)	(0.01)	(0.02)	(50)

During the third quarter of 2011, the Company recorded a net loss of \$540,761 (\$nil per basic and diluted share) versus a net loss of \$497,473 (\$0.01 per basic and diluted share) in the same period of 2010. In the nine month period ended September 30, 2011, the Company incurred a net loss of \$1,203,732 (\$0.01 per basic and diluted share) as compared to the net loss of \$1,687,713 (\$0.02 per basic and diluted share) recorded in the corresponding period of 2010. The decrease in the Company's net loss during the

three and nine month ended periods of September 30, 2011, in comparison to the same periods of 2010, is largely a result of the net operating profit earned on the Company's Mervin production field that became fully operational near the end of 2010.

Capital Expenditures

During the third quarter of 2011, the Company spent \$1,223,778 on development and production activities, which consisted of the facility upgrades at its water disposal facility at Mervin and the pipelining of the six Mervin wells to the facility. The water disposal facility will handle all the produced water from the Company's six Mervin wells and also have considerable capacity to accept third-party volumes, thereby allowing Forent to seeing significant cost savings and a potential new revenue source. The Company also sold its interest in 2 wells in the Provost, Alberta area for \$750,000 that resulted in a loss on disposal of \$116,763 representing a decrease from the carrying value of the properties held in development and production assets. Exploration and evaluation activities resulted in \$936,388 being expended primarily on the 2D seismic program at Alton.

Liquidity and Capital Resources

	Three months ended September 30,			Nine months ended September 30,		
	2011	2010	Change	2011	2010	Change
	(\$)	(\$)	(%)	(\$)	(\$)	(%)
Working capital, beginning of year	2,177,941	2,689,732	(19)	807,093	1,182,925	(32)
Funds from operations	151,947	49,173	209	445,843	(208,388)	(314)
Issue of capital stock (net)	-	-	-	2,575,171	4,510,909	(43)
Change in flow-through share premium	-	-	-	(22,402)	(43,425)	(48)
Capital expenditures (net)	(743,919)	(1,662,839)	(55)	(2,219,736)	(4,365,955)	(49)
Working capital, end of period	1,585,969	1,076,066	47	1,585,969	1,076,066	47

Forent opened 2011 with a working capital surplus of \$0.8 million. The change in the Company's net working capital resulted from funds from operations of \$0.4 million, net equity of \$2.6 million from a flow-through share financing and warrant exercises, net capital expenditures totalling \$2.2 million, thereby leaving the Company with a working capital surplus of \$1.6 million at September 30, 2011. For the purposes of the working capital calculation the Company does not include the flow-through share deferred liability, which was \$562,750 and \$251,818 as at September 30, 2011 and 2010, respectively. The liability is extinguished at the time the Company fulfills its flow-through share commitments and renounces the flow-through expenditures to investors.

The Company's 2011 capital budget includes up to \$5.5 million to conduct a 2D seismic program and to drill three exploration wells on the Alton Block in Nova Scotia. The anticipated expenditures will be applied towards the Alton Block commitment Forent made under its three year exploration license requiring \$6.3 million to be expended over the three year term ending April 8, 2014.

The Company intends to raise new capital or utilize other alternative means such as joint venturing to meet the stated Nova Scotia commitments, however, there is no certainty that the financing activities will be successful. Additional capital expenditures may be made if funds from operations are available to develop various oil focused, low risk projects in western Canada.

Share Capital

The Company has authorized an unlimited number of common and preferred shares with no par value. At September 30, 2011, the Company had 115,231,188 common shares outstanding and no preferred shares outstanding.

The following table is a summary of the Company's share information as at the periods indicated:

Nine months ended September 30,	2011	2010
	(#)	(#)
Common Shares		
Balance – beginning of year	102,847,022	69,937,686
Issued pursuant to acquisition of Edelex	-	327,771
Issued pursuant to private placements	9,379,167	21,470,455
Issued pursuant to warrants exercised	3,004,999	-
Balance – end of period	115,231,188	91,735,912
Weighted Average Common Shares Outstanding⁽¹⁾		
Basic and Diluted	109,047,696	83,478,045
Share Purchase Warrants		
Balance – beginning of year	15,505,755	7,918,255
Issue of warrants	488,833	7,587,500
Exercise of warrants	(3,004,999)	-
Expiry of warrants	(3,585,926)	-
Balance – end of period	9,403,663	15,505,755
Stock Options		
Beginning of period	5,704,490	4,841,110
Granted	3,100,000	945,000
Cancelled	(232,454)	-
Granted pursuant to re-pricing	1,889,355	-
Cancelled pursuant to re-pricing	(3,778,704)	-
End of period	6,592,687	5,786,110

(1) *Anti-dilutive stock options and warrants have been excluded from the dilution calculation.*

Quarterly Data

	Three months ended Dec. 31, 2010	Three months ended Mar. 31, 2011	Three months ended Jun. 30, 2011	Three months ended Sep. 30, 2011
	(\$)	(\$)	(\$)	(\$)
Oil and gas revenue	1,152,596	921,024	1,297,141	916,923
Funds from (used in) operations ⁽¹⁾	180,398	(11,046)	304,942	151,947
Per share – basic and diluted	-	-	-	-
Net loss	(425,465)	(581,215)	(81,756)	(540,761)
Per share – basic and diluted	-	(0.01)	-	(0.01)
Capital expenditures	2,242,327	696,841	778,976	1,603,919
Working capital	807,093	240,306	2,177,941	1,585,969
Shareholders' equity	11,004,627	10,711,069	12,599,563	12,123,010
Average daily production				
Natural gas (mcf/d)	736	559	465	452
Crude oil and NGLs (bbls/d)	194	148	204	147
Total (boe/d)	317	241	281	222

**Prepared with
previous Canadian GAAP Prepared with current
Canadian GAAP**

	Three months ended Dec. 31, 2009	Three months ended Mar. 31, 2010	Three months ended Jun. 30, 2010	Three months ended Sep. 30, 2010
	(\$)	(\$)	(\$)	(\$)
Oil and gas revenue	210,909	342,091	435,054	773,448
Funds from (used in) operations ⁽¹⁾	(157,857)	(159,712)	(97,843)	49,174
Per share – basic and diluted ⁽²⁾	-	-	-	-
Net loss	(349,768)	(897,250)	(292,986)	(497,471)
Per share – basic and diluted ⁽²⁾	(0.01)	(0.01)	(0.01)	(0.01)
Capital expenditures	1,706,217	454,782	2,248,333	1,662,839
Working capital	1,182,925	648,238	2,689,732	1,076,066
Shareholders' equity	8,690,124	6,246,631	10,182,756	9,748,250
Average daily production				
Natural gas (mcf/d)	434	572	698	604
Crude oil and NGLs (bbls/d)	5	23	33	116
Total (boe/d)	77	118	149	216

(1) Funds from operations is defined as cash provided by operations before changes in non-cash operating working capital.

Related Party Transactions

The Company enters into various transactions with related parties from time to time. These transactions are entered into under the normal course of operations, non-secured and are to be settled in cash. No provisions for doubtful accounts have been made during the period ended September 30, 2011 and 2010 in regards to related parties.

During the three and nine months ended September 30, 2011 and 2010, the Company had the following related party transactions:

In January 2011 the Company incurred \$36,000 to acquire oil and gas equipment from a company controlled by a significant shareholder. Pursuant to the purchase of the equipment the Company ended its rental relationship with the significant shareholder's company and renegotiated a lower cost buyout of the pipeline facilities that will be completed on December 31, 2011. As a result of the purchase there were no operating costs relating to pipeline and facility rental fees in the three and nine months ended September 30, 2011 (2010 - \$25,997 and \$79,492). At September 30, 2011, there was an outstanding balance of \$4,083 (September 30, 2010 - \$8,574).

During the three and nine months ended September 30, 2011, the Company incurred \$17,226 and \$50,910 (2010 - \$2,422 and \$2,422) of operating costs relating to pipeline compressor rental fees, respectively, from a company controlled by a board member. The board member became a related party upon acceptance of a board position effective September 1, 2010. As at September 30, 2011, there was an outstanding balance of \$18,507 (September 30, 2010 - 2,543) owed to the related company. The pipeline and facility rental fees and outstanding balance were incurred on facilities that the Company operates with approximately an average 20% working interest. As such, 80% of the gross operating costs and outstanding balances are directly attributed to the Company's joint venture partner, being a large and well-funded petroleum producer.

During the three and nine months ended September 30, 2011 the Company incurred \$20,931 and \$46,889 (2010 - \$42,612 and \$48,839) for legal services, respectively, with a law firm of which a board member is a partner. As at September 30, 2011, there was an outstanding balance of \$435 (September 30, 2010 - \$28,261) owed for legal services.

Compensation for key management

Key management includes the company's directors and executives. Compensation awarded to key management included the following:

For the period ended,	September 30, 2011	September 30, 2010
	(\$)	(\$)
Salaries and employee benefits	285,710	265,277
Share based payments	60,853	58,587
	346,563	323,864

Off Balance Sheet Transactions

Forent was not involved in any off balance sheet transactions as at September 30, 2011. In addition, the Company did not have any outstanding risk management contracts as at September 30, 2011.

Contractual Obligations

On June 1, 2011, the Company issued flow-through shares requiring that \$2,251,000 in qualifying exploration expenditures be expended by December 31, 2012. As at September 30, 2011 the Company has incurred approximately \$1.6 million of qualifying expenditures with approximately \$0.7 million remaining to be expended.

The Company is committed to expend a minimum of \$6,300,000 on the Alton Block over a three year period, ending April 8, 2014, in a work program consisting of initiation and interpretation of geological, geophysical, geomagnetic and geochemical data and culminating in an exploration and well testing

program within the boundaries of the Alton Block. The Company's capital 2011/2012 budget includes up to \$5.0 million to conduct a 2D seismic program and to drill three exploration wells on the Alton Block in Nova Scotia, which will be applied towards the commitment. The seismic program was completed in the first half of 2011 and the first of the three exploration wells is expected to be drilled mid-December 2011.

The Company relinquished its Beech Hill Block exploration agreement on September 19, 2011, which removed the commitment to expend a minimum of \$2,070,000 over a three year period, ending May 1, 2011 and any future commitments. As a result of the Company not continuing its exploration of oil and natural gas within the block the Company has forfeited \$59,400 of an \$110,000 deposit that was held by the government of Nova Scotia, with \$50,600 being returned to the Company.

Transition to IFRS from Canadian GAAP

A reconciliation of the new and revised standards and interpretations is outlined in Note 16 of the September 30, 2011 interim financial statements.

The following discussion explains the significant differences between previous Canadian GAAP accounting policies and those applied by the Company under IFRS. IFRS policies have been applied retrospectively except where IFRS 1 exemptions permitted an alternative treatment upon transition to IFRS for first time adopters.

Property, Plant and Equipment ("PP&E")

For PP&E a Company has the option to elect fair value at the date of transition as the deemed cost for its PP&E or to use a revalued amount according to its previous Canadian GAAP if the revaluation, at the date of revaluation, is comparable to fair value or depreciated cost in accordance with IFRS or to measure oil and gas assets at the date of the transition to IFRS at the amount previously determined under previous Canadian GAAP.

Forent has elected to value its P&E as previously determined under Canadian GAAP. The measurement upon transition to IFRS is as follows: 1) exploration and evaluation assets were reclassified from the full cost pool method to exploration and evaluation ("E&E") assets at the amount that was previously recorded under Canadian GAAP, and 2) the remaining full cost pool of costs was allocated to development and producing assets on a pro-rata basis using reserve values discounted at 10% for its proved plus probable company interest reserves. This resulted in \$1,285,167 of E&E costs being transferred from development and production assets.

Exploration and Evaluation

Under previous Canadian GAAP, petroleum and natural gas properties included certain exploration and evaluation expenditures incurred within a country based cost centre. These costs include, but are not limited to, exploration license expenditures, leasehold acquisition costs, evaluation costs including drilling costs directly attributable to an identifiable well and directly attributable general and administrative costs. Under IFRS, such exploration and evaluation expenditures are recognized as tangible or intangible based on their nature and subject to technical, commercial and management review at least once a year to confirm the continued intent to develop or otherwise extract value from the discovery. When this is no longer the case, the costs are expensed.

Exploration and evaluation assets at January 1, 2010 were deemed to be \$1,285,167, being the amount recorded as the undeveloped properties without proved or probable reserves attributed under previous Canadian GAAP. This has resulted in \$1,285,167 being reclassification from property, plant and equipment to E&E assets in the opening IFRS balance sheet. In the nine months ended September 30, 2010, the Company recorded \$330,477 to exploration and evaluation expense in relation to E&E expenditures not expected to be recovered. During the three months ended September 30, 2010, the Company recorded \$101,000 to exploration and evaluation expense in relation to E&E expenditures on undeveloped lands.

Decommissioning liabilities

Under Canadian GAAP the Company discounted its liability using a credit-adjusted risk free rate. Under IFRS, the Company has chosen to use a risk-free discount rate. Therefore under IFRS the decommissioning liabilities are higher due to the lower discount rates used. IFRS 1 provides an exemption, which the Company has elected, and allows the Company to measure decommissioning liabilities as at the date of transition and to recognize directly in the Company's retained earnings any difference between that amount and the carrying amount of those liabilities at the date of transition to IFRS.

The adjustment to the discounted decommissioning liability recognized at January 1, 2010 was an increase to the liability of \$91,059. Under an IFRS 1 election, this adjustment has been offset directly to equity on transition. The adjustment to the discounted decommissioning liability recognized for the three and nine months ended September 30, 2010 were increases of \$60,268 and \$117,464, respectively.

Under GAAP the accretion expense was presented as part of the depletion, depreciation and amortization expense. IFRS requires that the expense be presented as a financing cost.

Depletion Policy

Previous Canadian GAAP provided specific guidelines on the calculation of depletion for oil and natural gas properties. Previously, depletion was calculated on the unit-of-production method using proved reserves as their base. Under IFRS, the Company had a choice as to the reserve base used in its depletion calculations. The Company has adopted the policy of depleting its oil and natural gas properties using its proved plus probable reserve base. Also, depletion calculations under previous GAAP were done on a country based cost centre basis with Forent only having one cost centre. Under IFRS, the Company is required to calculate depletion based on individual components that the Company has identified to be at the geographic area level. The adoption of this policy was effective as of the transition date.

For the nine months ended September 30, the DD&A expense decreased by \$102,919. The change resulted in a decrease of \$75,416 in combined depletion and impairments under IFRS, offset by \$27,503 of accretion not recorded in DD&A and being reclassified to finance expense. Amortization of other assets remained the same.

For the three months ended September 30, 2010, the Company's DD&A decreased \$118,455. The change resulted in an increase of \$103,522 in combined depletion and impairments under IFRS, offset by \$14,933 of accretion not recorded in DD&A and being reclassified to finance expense. Amortization of other assets remained the same.

Impairment Test

IFRS requires an asset impairment test to be conducted on the transition date and subsequently when indicators of impairment are present. Under Canadian GAAP, impairment of long-lived assets is assessed on the basis of an asset's estimated undiscounted future cash flows compared with the asset's carrying amount and if impairment is indicated, discounted cash flows are prepared to quantify the amount of impairment. The impairment test under previous Canadian GAAP was done at the cost centre level with Forent only having one cost centre.

IFRS requires the impairment test to occur at the asset level or the cash generating unit ("CGU") level when long-lived assets exist that do not generate independent cash inflows. The carrying amount of the asset or CGU is compared to its recoverable amount which is the higher of the value-in-use or the fair value of the assets less the costs to sell it.

Forent performed an impairment test on transition to IFRS as at January 1, 2010 based on fair value less estimated costs to sell. Fair value was based on the most recent reserve report as evaluated by the Company's independent engineers. The Company recorded an impairment of \$1,850,945 on the transition date.

During the nine months ended September 30, 2010 an impairment of \$293,676 was recognized on the Company's assets. For the three months ended September 30, 2010, an impairment of \$61,003 was recognized. The impairments reflect the historically low natural gas pricing environment and forecasted outlook.

Flow-through Shares

Under GAAP, the aggregate tax effect of all flow-through share renouncements in excess of the premium liability associated with flow-through share issuances were recognized as a reduction of share capital. No specific guidance is provided regarding this issue under IFRS; however, it has been interpreted that guidance applied under US GAAP is acceptable under IFRS. Under US GAAP, issuance proceeds were disaggregated between the fair market value of the shares issued and the premium paid for the renounced expenditures. A deferred tax liability is accrued upon effective date of the renouncement and the deferred tax expense is charged to net earnings rather than to share capital.

On transition to IFRS at January 1, 2010, the adjustment recorded related to the 2007 and 2008 flow-through common shares that were renounced and fully expended, prior to December 31, 2009, was a credit to common shares of \$395,912 and a corresponding debit to retained earnings for \$395,912. For the 2009 flow-through share issuance the company debited the common shares by \$295,242 and credited the flow-through share tax current liability for \$295,242, to reflect the renouncement liability and corresponding decrease in the common shares at the date of transition. The net effect on the common shares was an increase of \$100,669.

During 2010 the Company issued flow-through shares in April and December. For the nine months ended September 30, 2010, the Company maintained the above transition adjustments and recorded additional adjustments of a debit to the deferred tax expense of \$181,754, debit to the flow-through share tax current liability of \$295,242 and credited the deferred tax liability \$476,996.

For the three months ended September 30, 2010, the Company maintained the above transition adjustments and recorded the following adjustments. In addition, the Company issued flow-through shares in April 2010, resulting in decreasing the common shares by \$251,818 and crediting the flow-through share tax current liability for \$251,818, thereby setting up a flow-through liability related to the April 2010 issuance.

Critical Accounting Estimates

The preparation of financial statements in conformity with IFRS requires management to make judgements, estimates and assumptions that affect the application of accounting policies and the reported amounts of assets, liabilities, income and expenses. Actual results may differ from these estimates.

Estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognized in the year in which the estimates are revised.

Accounts receivable

Accounts receivable are recorded at the estimated recoverable amount that includes an estimate of uncollectible amounts.

Property, plant and equipment

The Company's oil and natural gas reserves are determined using estimates of oil and natural gas in place, recovery factors and future prices by an independent reserve engineering firm. A significant number of estimates and assumptions are made in determining the reserves in place and the valuation of those reserves, requiring many judgements based on geological, geophysical, engineering and economic data. These estimates may change, having either a positive or negative impact on net earnings as further information becomes available and as the economic environment changes. The reserves estimate is a key driver in determining the Company's depletion rate and used in impairment testing.

Oil and natural gas assets are grouped into cash generating units ("CGUs") that have been identified as being the smallest identifiable group of assets that generate cash flows that are independent of cash

flows of other assets or groups of assets. The determination of these CGUs was based on management's judgment in regards to shared infrastructure, geographical proximity, petroleum type and similar exposure to market risk and materiality.

Decommissioning liabilities

The calculation of decommissioning liabilities includes estimates of the ultimate settlement amounts, inflation factors, risk free rates, and timing of settlement. The actual decommissioning costs are uncertain and the estimates can vary in response to changes in regulatory requirements and new restoration techniques. The impact of future revisions to these assumptions on the interim financial statements of future periods could be significant.

Share based compensation

The fair value of employee stock options is measured using a Black Scholes option pricing model. The option pricing model requires management to estimate expected volatility, weighted average expected life, expected forfeiture rate, expected dividends, and the risk-free interest rate (based on government bonds). The expected volatility, life of the options and forfeiture rates are based upon historical experience. Dividends are assumed to be nil, as management does not anticipate any dividends to be paid in the future. The risk-free rate is based upon government bond rates at the time of issuance of the options.

Deferred taxes

Tax interpretations, regulations and legislation in which the Corporation and its subsidiaries operate are subject to change. As such, income taxes are subject to measurement uncertainty. Management assumes that the Company will use its tax pools to the full extent in future periods and has determined its deferred tax balance on that basis.

Recent accounting pronouncements

The accounting standards effective for periods on or after January 1, 2011 have been adopted as part of the transition to IFRS. The following new IFRS pronouncements have been issued but are not yet effective and may have an impact on the Corporation in the future.

IFRS 9 – Financial Instruments

IFRS 9, as issued reflects the first phase of the IASB's work on the replacement of IAS 39 and applies to classification and measurement of financial assets and liabilities as defined in IAS 39. The standard is effective for annual periods beginning on or after January 1, 2013. The adoption of this standard is not expected to have a significant impact on the financial statements.

IFRS 10 – Consolidated Financial Statements

IFRS 10 requires an entity to consolidate an investee when it is exposed, or has rights, to variable returns from its involvement with the investee and has the ability to affect those returns through its power over the investee. Under existing IFRS, consolidation is required when an entity has the power to govern the financial and operating policies of an entity so as to obtain benefits from its activities. IFRS 10 replaces SIC-12 *Consolidation-Special Purpose Entities* and parts of IAS 27 *Consolidated and Separate Financial Statements*. The adoption of this standard is not expected to have a significant impact on the financial statements.

IFRS 11 – Joint Arrangements

IFRS 11 requires a venture to classify its interest in a joint arrangement as a joint venture or joint operation. Joint ventures will be accounted for using the equity method of accounting whereas for a joint operation the venture will recognize its share of the assets, liabilities, revenue and expenses of the joint operation. Under existing IFRS, entities have the choice to proportionately consolidate or equity account for interest in joint ventures. IFRS 11 supersedes IAS 31, *Interests in Joint Ventures* and SIC-13, *Jointly Controlled Entities, Non-Monetary Contributions by Venturers*. The adoption of this standard is not expected to have a significant impact on the financial statements.

IFRS 12 – Disclosure of Interest in Other Entities

IFRS 12 establishes disclosure requirements for interests in other entities, such as joint arrangements, associates, special purpose vehicles and off balance sheet vehicles. The standard carries forward existing disclosures and also introduces significant additional disclosure requirements that address the nature of, and risks associated with, an entity's interest in other entities. The adoption of this standard is not expected to have a significant impact on the financial statements.

IFRS 13 – Fair Value Measurement

IFRS 13 is a comprehensive standard for fair value measurement and disclosure requirements for use across all IFRS standards. The new standard clarifies that fair value is the price that would be received to sell an asset, or paid to transfer a liability in an orderly transaction between market participants, at the measurement date. It also establishes disclosures about fair value measurement. Under existing IFRS, guidance on measuring and disclosing fair value is dispersed among the specific standards requiring fair value measurement and in many cases does not reflect a clear measurement basis or consistent disclosures. The adoption of this standard is not expected to have a significant impact on the financial statements.

IAS 27 – Separate Financial Statements

IAS 27 contains accounting and disclosure requirements for investments in subsidiaries, joint ventures and associates when an entity prepares separate financial statements. The Standard requires an entity preparing separate financial statements to account for those investments at cost or in accordance with IFRS 9 *Financial Instruments*. This standard is effective for annual periods beginning on or after January 1, 2013. The adoption of this standard is not expected to have a significant impact on the financial statements.

IAS 28 – Investment in Associates and Joint Ventures

IAS 28 prescribes the accounting for investments in associates and sets out the requirements for the application of the equity method when accounting for investments in associates and joint ventures. Effective for annual periods beginning on or after January 1, 2013, the standard has been amended to include joint ventures in its scope and to address the changes in IFRS 10 – 13. The adoption of this standard is not expected to have a significant impact on the financial statements.

Risks and Uncertainties

The Company is exposed to a number of risks and uncertainties inherent in exploring for, developing and producing crude oil and natural gas. These risks and uncertainties include but are not limited to, the following:

- risk of finding and producing reserves economically;
- uncertainty associated with obtaining drilling licenses and other consents and approvals;
- production risk associated with sour hydrocarbons;
- marketing reserves at acceptable prices;
- cost of capital risk associated with securing the needed capital to carry out the Company's operations;
- risk of fluctuating foreign currency exchange rates;
- risk of governmental policies, social instability or other political, economic or diplomatic developments in its operations;
- market risks associated with investing the Company's cash reserves in interest bearing depository instruments; and
- environmental risks related to its oil and gas properties.

Many of the previously mentioned risks are beyond the Company's control, and it is impossible to ensure that any exploration drilling program will result in commercial operations. As at December 31, 2010 the Company had no derivative instruments to hedge its commodity price, foreign currency exchange or interest rate risks in place. The Company may enter into such risk management contracts from time to time as appropriate.

Forent strives to minimize and manage these risks in a number of ways including:

- Employing qualified professional technical staff;
- Communicating openly with members of the public regarding its activities;
- Concentrating in a limited number of operation areas;
- Utilizing the latest technology for finding and developing reserves;
- Constructing high-quality, environmentally sensitive, safe production facilities; and
- Maximizing operational control of drilling and producing operations;

Design and Evaluation of Internal Controls Related to Disclosure Controls and Procedures

The CEO and CFO of Forent is responsible for designing internal controls or causing them to be designed under his supervision, in order to provide reasonable assurance regarding disclosure controls and procedures that: (1) ensures information required to be disclosed by the Company is assembled and communicated to management; and (2) information required to be disclosed by the Company in its annual filings, interim filings or other reports filed or submitted by it under securities legislation is recorded, processed, summarized and reported within the time period specified in securities legislation. The Company's CEO and CFO has concluded based on his evaluation that disclosure controls and procedures are effective as at September 30, 2011.

Design and Evaluation of Internal Controls Related to Financial Reporting

The CEO and CFO of Forent is responsible for designing internal controls over financial reporting or causing them to be designed under his supervision in order to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with Canadian GAAP. Management has evaluated the Company's internal control over financial reporting as of September 30, 2011 and has certified that the controls over financial reporting are effective and includes those policies and procedures that:

- pertain to the maintenance of records with such reasonable detail that accurately and fairly reflects the transactions of the issuer;
- provide reasonable assurance that transactions are recorded as necessary to permit the preparation of the financial statements in accordance with Canadian GAAP and that the receipts and expenditures of the issuer are being made in accordance with the authorization of the management and directors of the Company; and
- provide reasonable assurance regarding the prevention or timely detection of unauthorized acquisition, use or disposition of the issuer's assets that could have a material effect on the annual or interim financial statements.

Despite the CEO and CFO certifying that the Company's internal controls over financial reporting and disclosure controls and procedures are effective to provide a reasonable level of assurance, he is not able to conclude that the controls and procedures are capable of preventing all frauds and errors. Regardless of how well conceived or managed, a control system is incapable of providing absolute assurance to prevent all errors and fraud, as only reasonable assurance that the objectives of a control system can be obtained.

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² *Chairman of the Board*

³ *Technical Committee*

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