This is Delphi.

DELPHI ENERGY CORP. | FOR THE NINE MONTHS ENDED SEPTEMBER 30, 2011

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Q3

Third Quarter 2011 Highlights

- achieved record production in the third quarter with average daily volumes of 8,967 barrels of oil equivalent per day (boe/d), an increase of 11 percent compared to the third quarter of 2010;
- increased oil and natural gas liquids production by 60 percent to 2,469 bbls/d compared to 1,541 bbls/d in the third quarter of 2010, changing the production mix to approximately 28 percent crude oil and natural gas liquids in the third quarter of 2011;
- generated funds from operations (cash flow) of $17.2 million, an increase of 15 percent from the comparative quarter of 2010;
- reduced operating costs by eight percent to $6.85 per boe in the third quarter of 2011 from $7.44 per boe in the third quarter of 2010;
- achieved an operating netback of $24.10 per boe and a cash netback of $20.87 per boe in the third quarter of 2011 compared to $23.29 per boe and $20.08 per boe, respectively, in the third quarter of 2010;
- realized $2.2 million ($2.62 per boe) in hedging gains on commodity contracts in the third quarter of 2011 compared to $4.9 million ($6.58 per boe) in the third quarter of 2010, providing stability to cash flow and balance sheet strength; and
- increased cash netbacks (excluding hedging gains) by 35 percent compared to third quarter of 2010 as a result of increased oil and NGL production, higher commodity prices and lower costs.

Financial Highlights ($ thousands except per unit amounts)

	Three Months Ended September 30			Nine Months Ended September 30		
	2011	2010	% Change	**2011**	2010	% Change
Petroleum and natural gas sales	**32,194**	26,554	21	**93,772**	83,980	12
Per boe	**40.78**	37.62	8	**40.49**	40.04	1
Funds from operations	**17,213**	14,988	15	**49,791**	42,544	17
Per boe	**20.87**	20.08	4	**20.92**	19.64	7
Per share – Basic	**0.15**	0.13	15	**0.43**	0.40	8
Per share – Diluted	**0.14**	0.13	8	**0.42**	0.40	5
Net earnings (loss)	**4,058**	(20,472)	-	**10,777**	(18,728)	-
Per boe	**4.92**	(27.43)	-	**4.53**	(8.65)	-
Per share – Basic	**0.03**	(0.18)	-	**0.09**	(0.18)	-
Per share – Diluted	**0.03**	(0.18)	-	**0.09**	(0.18)	-
Capital invested	**33,356**	43,794	(24)	**77,195**	86,514	(11)
Disposition of properties	**(7,702)**	4	-	**(8,038)**	(247)	3,154
Net capital invested	**25,654**	43,798	(41)	**69,157**	86,267	(20)
Acquisition of properties	**130**	2	6,400	**217**	387	(44)
Total capital invested	**25,784**	43,800	(41)	**69,374**	86,654	(20)

	Sept. 30 2011	Dec. 31 2010	% Change
Debt plus working capital deficiency [1]	**116,285**	108,054	8
Total assets	**436,538**	387,687	13
Shares outstanding (000's)			
Basic	**117,935**	112,825	5
Diluted	**126,714**	119,501	6

[1] excludes risk management asset and the related current future income taxes.

Operational Highlights

	Three Months Ended September 30			Nine Months Ended September 30		
Production	**2011**	2010	% Change	**2011**	2010	% Change
Natural gas (mcf/d)	**38,989**	39,439	(1)	**37,662**	38,780	(3)
Crude oil (bbls/d)	**1,395**	831	68	**1,282**	884	45
Natural gas liquids (bbls/d)	**1,074**	710	51	**1,154**	586	97
Total (boe/d)	**8,967**	8,114	11	**8,714**	7,933	10

MESSAGE TO SHAREHOLDERS

Production during the third quarter of 2011 averaged 8,967 boe/d, an increase of 11 percent compared to 8,114 boe/d in the third quarter of 2010. The increased light oil production at Hythe and Bigstone and growing liquids production at Wapiti changed the production mix in the quarter to 28 percent liquids (72 percent natural gas), from 19 percent liquids (81 percent natural gas) in the third quarter of 2010. The change in production mix to higher netback oil and natural gas liquids was a significant contributor to third quarter cash flow.

Cash flow in the third quarter of 2011 was $17.2 million or $0.15 per basic share, compared to $15.0 million or $0.13 per basic share in the comparative quarter of 2010. The growth in cash flow in 2011 over 2010 was primarily a result of the continued reduction in operating costs, change in production mix towards higher netback crude oil and natural gas liquids production and the increase in realized oil and natural gas liquids prices offset by lower realized natural gas prices.

For the quarter ended September 30, 2011, the Company recognized approximately $2.2 million in realized gains on financial and physical hedging contracts providing stability to the Company's cash flow.

The combination of the above highlighted items resulted in Delphi's financial position continuing to remain strong at the end of the third quarter of 2011, providing the financial flexibility to execute its ongoing capital program. At September 30, 2011, the Company had net debt of $116.3 million on total credit facilities of $145.0 million, providing excess financial capacity of approximately $28.7 million. On an annualized, third quarter funds from operations basis, Delphi's net debt to cash flow ratio was 1.7:1. Net debt includes bank debt plus working capital deficiency excluding the fair value of financial instruments.

Operations

The Company has been very active increasing its Montney land position at Bigstone. A total of 45 sections (41.5 net) of undeveloped land, prospective for liquids-rich natural gas in the Montney formation, have been accumulated. The Company has increased its Montney rights on the Bigstone East block from 4.25 gross sections to 13 sections (11.0 net) through Crown land sales. Delphi will earn an additional five gross sections (3.75 net) at Bigstone East through an industry farm-in, with the drilling of its third Montney well, planned to commence drilling prior to year-end. At Bigstone West, the Company holds 27 gross (26.75 net) sections of Montney rights. The Montney in the area is currently being developed utilizing four horizontal wells per section.

The first well, located on the East block, will be drilled from a surface location at 1-19-60-22 W5M with a planned total measured depth of 5,700 metres. The second well, on the West block, will be drilled from a surface location at 1-33-59-24 W5M with a planned total measured depth of 6,000 metres. The targeted 2,750 metre "extended-reach" horizontal section in both wells will be completed utilizing oil-based fracturing fluids and multi-stage fracturing technology.

Two drilling rigs have moved into Bigstone to kick off its Montney horizontal drilling program and have now commenced operations. The Company has incorporated into its drilling and completion plans, existing vertical well control including Montney core analysis as well as information available from ten recently drilled horizontal wells offsetting the Company's acreage. The targeted extended-reach horizontal sections are up to twice as long as older horizontal wells and are designed to reduce the number of wells required for full development by up to 50 percent and cost savings of approximately 35 percent.

The Company has also kicked off its winter program with the drilling of a horizontal Falher well at its Hythe property and is finalizing plans to drill a horizontal Gething well in Bigstone beginning in late December. Drilling activity in Wapiti is also anticipated to resume in late December targeting natural gas and associated NGL's averaging 80 barrels per million cubic feet (bbls/mmcf). Final winter drilling plans will be dependent on the results of the first two Montney wells, also expected in late December.

During the third quarter, the Company drilled nine wells (6.2 net) within its core areas of Wapiti and Hythe. Two horizontal wells (1.4 net) targeted light oil in the Doe Creek formation at Hythe, both of which have been brought on production. A third (1.0 net) vertical well was drilled in Hythe to further evaluate the natural gas potential in the Falher formation. A core was cut in this well, for reservoir characterization purposes, through the strategraphic interval where the Company has drilled three and identified approximately 60 to 70 follow-up horizontal locations. This well is expected to be tied-in during the fourth quarter. At Wapiti, six vertical wells (3.8 net) targeting liquids-rich gas in the Nikanassin and uphole Cretaceous intervals were drilled and cased during the third quarter. Completion and tie-in operations were concluded on four wells (2.7 net).

At Hythe, the Company continues to advance its plan to improve the efficiency of the existing natural gas liquids ("NGL") recovery system at its processing facility. It is anticipated that the liquids recovery will increase NGL production in the Hythe area from five bbls/mmcf to 20 to 25 bbls/mmcf. The Company continues to pursue options with its partners in the facility to achieve a stronger netback from its Hythe natural gas production.

Outlook

The Company expects to spend an estimated net $90.0 - $95.0 million in 2011, with field capital directed towards drilling opportunities in the Bigstone, Hythe and Wapiti core areas. The guidance range for 2011 production volumes has been tightened to 8,800 to 9,000 boe/d.

Delphi expects 2011 AECO natural gas prices to average approximately Cdn. $3.70 per mcf for forecast purposes and towards that end, has mitigated downside commodity price risk with an active natural gas hedging program. For the remainder of 2011, the Company is hedged with approximately 51 percent of its natural gas production protected at an average floor price of $4.88 per mcf. The growth in production of liquids volume, increased hedging and lower operating costs, offset by lower natural gas prices are expected to result in cash flow for 2011 of $65.0 to $69.0 million.

Bank debt, including working capital, is estimated to be between $120.0 million and $125.0 million at December 31, 2011 resulting in a debt to cash flow ratio of approximately 1.9:1.

The Company has grown on the strength of its superior cash generating capabilities, solid reserve base with a comfortable 26 percent annual decline profile and large inventory of robust deep basin liquids-rich natural gas projects. Given the significant drill-ready project inventory, the Company remains focused on the acceleration of its growth profile.

On behalf of the Board of Directors and all the employees of Delphi, we would like to thank our shareholders for their continued support as we remain focussed on sustainable, capital efficient growth of the Company's production and reserve base while maintaining the financial strength and flexibility to take advantage of strategic opportunities.

On behalf of the Board,

David J. Reid
President and Chief Executive Officer
November 8, 2011

MANAGEMENT'S DISCUSSION AND ANALYSIS

(All tabular amounts are stated in thousands of dollars, except per unit amounts)

Management's discussion and analysis ("MD&A") has been prepared by management and reviewed and approved by the Board of Directors of Delphi Energy Corp. ("Delphi" or "the Company"). The discussion and analysis is a review of the financial position and results of operations of the Company. Its focus is primarily a comparison of the financial performance for the three and nine months ended September 30, 2011 and 2010 and should be read in conjunction with Note 7 of the unaudited interim consolidated financial statements and accompanying notes for the three and nine months ended September 30, 2011 and the audited consolidated financial statements and accompanying notes for the years ended December 31, 2010 and 2009. The unaudited interim consolidated financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS") including International Accounting Standard 34 "Interim Financial Reporting". The reporting currency is the Canadian dollar. The discussion and analysis has been prepared as of November 8, 2011.

For the purpose of reporting production information, reserves and calculating unit prices and costs, natural gas volumes have been converted to a barrel of oil equivalent ("boe") using six thousand cubic feet equal to one barrel. A boe conversion ratio of 6:1 is based upon an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. This conversion conforms to the Canadian Securities Administrators' National Instrument 51-101 when boes are disclosed. Boes may be misleading, particularly if used in isolation.

The MD&A contains the terms "funds from operations", "funds from operations per share", "net debt", "cash operating costs" and "netbacks" which are not recognized measures under IFRS. The Company uses these measures to help evaluate its performance. Management considers netbacks an important measure as it demonstrates its profitability relative to current commodity prices. Management uses funds from operations to analyze performance and considers it a key measure as it demonstrates the Company's ability to generate the cash necessary to fund future capital investments and to repay debt. Funds from operations is a non-IFRS measure and has been defined by the Company as net earnings plus the add back of non-cash items (depletion and depletion, accretion, stock-based compensation, exploration and evaluation expenses, deferred income taxes, gain on dispositions and unrealized gain/(loss) on financial instruments) and excludes the change in non-cash working capital related to operating activities, expenditures on decommissioning obligations and accretion of long term debt. 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. Delphi's determination of funds from operations may not be comparable to that reported by other companies nor should it be viewed as an alternative to cash flow from operating activities, net earnings or other measures of financial performance calculated in accordance with IFRS. The Company has defined net debt as the sum of long term debt plus/minus working capital excluding the current portion of the fair value of financial instruments. Net debt is used by management to monitor remaining availability under its credit facilities. Cash operating costs have been defined as the sum of operating expenses, transportation expense, general and administrative expenses and cash finance costs. Operating netbacks have been defined as revenue less royalties, transportation and operating costs. Cash flow netbacks have been defined as operating netbacks less interest and general and administrative costs. Netbacks are generally discussed and presented on a per boe basis.

DELPHI'S OPERATIONS

What is the nature of Delphi's business and where are its operations?

Delphi Energy Corp. ("Delphi" or "the Company") is a publicly-traded company with its corporate office in Calgary, Alberta, Canada. Delphi is engaged in the exploration for, development and production of crude oil and natural gas from properties and assets located in Western Canada in which it holds an interest. The Company's operations are primarily concentrated in the Deep Basin of North West Alberta, representing in excess of 90 percent of the Company's production. The Company has three primary core areas in the Deep Basin located at Bigstone, Hythe and Wapiti.

THIRD QUARTER 2011 ACCOMPLISHMENTS

What were the highlights of Delphi's operational and financial results in the third quarter of 2011?

In the third quarter of 2011, the Company achieved the following:

- achieved average production of 8,967 barrels of oil equivalent per day ("boe/d"), an increase of eleven percent compared to the third quarter of 2010;
- increased the liquids percentage of production to approximately 28 percent crude oil and natural gas liquids in the third quarter of 2011, up from 19 percent in the third quarter of 2010;
- generated funds from operations ("cash flow") of $17.2 million, an increase of 15 percent from the comparative quarter of 2010;
- achieved a cash netback of $20.87 per boe, maintaining the Company's objective of achieving a cash netback of at least $20.00 per boe;
- reduced operating costs by 8 percent to $6.85 per boe in the third quarter of 2011 from $7.44 per boe in the comparative quarter of 2010;
- realized $2.3 million in hedging gains on natural gas physical and financial contracts while incurring $0.1 million of hedging losses on a financial crude oil call option; and
- drilled 9.0 gross (6.2 net) wells in the quarter as part of the Company's summer capital program.

Cash flow in the third quarter of 2011 was $17.2 million or $0.15 per basic share, compared to $15.0 million or $0.13 per basic share in the comparative quarter of 2010. The growth in cash flow in 2011 over 2010 was primarily a result of the continued reduction in operating costs, higher production, change in production mix towards higher netback crude oil and natural gas liquids and the increase in realized liquids prices offset by the decrease in realized natural gas prices.

The Company continues to focus production growth in its core areas where operating costs were less than $6.00 per boe on a weighted average basis. The Company's operating costs were reduced by $0.59 per boe to $6.85 per boe in the third quarter of 2011, eight percent lower than the comparative period. For the nine months ended September 30, 2011, operating costs were $6.75 per boe compared to $8.01 per boe for the comparative period of 2010.

For the three and nine months ended September 30, 2011, the Company recognized approximately $2.2 million and $5.5 million in realized gains on financial and physical hedging contracts providing additional stability to the Company's cash flow.

The combination of the above highlighted items resulted in Delphi's financial position continuing to remain strong at the end of the third quarter of 2011, providing the financial flexibility to complete its summer program and commence its Montney formation winter drilling program. At September 30, 2011, the Company had net debt of $116.3 million on total credit facilities of $145.0 million, providing excess financial capacity of approximately $28.7 million. On an annualized, third quarter funds from operations basis, Delphi's net debt to cash flow ratio was 1.7:1. Net debt includes bank debt plus working capital deficiency excluding the fair value of financial instruments.

2011 OUTLOOK AND FORWARD-LOOKING INFORMATION

This management discussion and analysis contains forward-looking statements and forward-looking information within the meaning of applicable securities laws. The use of any of the words "expect", "anticipate", "continue", "estimate", may", "will", "should", believe", "intends", "forecast", "plans", "guidance" and similar expressions are intended to identify forward-looking statements or information.

More particularly and without limitation, this management discussion and analysis contains forward-looking statements and information relating to the Company's risk management program, petroleum and natural gas production, future funds from operations, capital programs, commodity prices, costs and debt levels. The forward-looking statements and information are based on certain key expectations and assumptions made by Delphi, including expectations and assumptions relating to prevailing commodity prices and exchange rates, applicable royalty rates and tax laws, future well production rates, the performance of existing wells, the success of drilling new wells, the capital availability to undertake planned activities and the availability and cost of labour and services.

Although the Company believes that the expectations reflected in such forward-looking statements and information are reasonable, it can give no assurance that such expectations will prove to be correct. Since forward-looking statements and information address future events and conditions, by their very nature they involve inherent risks and uncertainties. Actual results may differ materially from those currently anticipated due to a number of factors and risks. These include, but are not limited to, the risks associated with the oil and gas industry in general such as operational risks in development, exploration and production, delays or changes in plans with respect to exploration or development projects or capital expenditures, the uncertainty of estimates and projections relating to production rates, costs and expenses, commodity price and exchange rate fluctuations, marketing and transportation, environmental risks, competition, the ability to access sufficient capital from internal and external sources and changes in tax, royalty and environmental legislation. Additional information on these and other factors that could affect the Company's operations or financial results are included in reports on file with the applicable securities regulatory authorities and may be accessed through the SEDAR website (www.sedar.com). The forward-looking statements and information contained in this MD&A are made as of November 3, 2011 for the purpose of providing the readers with the Company's expectations for the coming year. The forward-looking statements and information may not be appropriate for other purposes. Delphi undertakes no obligation to update publicly or revise any forward-looking statements or information, whether as a result of new information, future events or otherwise, unless so required by applicable securities laws.

Delphi's operational and financial expectations for 2011 are based upon the Company's projection of drilling plans, drilling success and production results and the estimated related revenues and associated costs of royalties, transportation expenses, operating costs, general and administrative expenses and interest costs. Commodity prices used in the determination of forecast revenues are based upon general economic conditions, commodity supply and demand forecasts and publicly available price forecasts. The Company continually monitors its forecast assumptions to ensure the stakeholders are informed of material variances from previously communicated expectations.

OPERATIONS

How many wells does Delphi expect to drill in 2011?

Delphi expects to drill 32 gross (24.7 net) wells in 2011 focused in its core areas of Bigstone, Hythe and Wapiti/Gold Creek. In Bigstone and Hythe, drilling will primarily be horizontal wells directed at light oil opportunities in the Cardium formation and Doe Creek formation, respectively. At Wapiti, the drilling will primarily be directed at vertical multi-zone opportunities with the liquids-rich Nikanassin formation being the primary target. Also at Bigstone, the Company will commence its Montney drilling program in the fourth quarter. The factors that may hinder Delphi from achieving its drilling plans include the availability of drilling rigs and equipment needed at the drill site, timely receipt of well licenses and permits and approval by the landowners for surface access to the location.

What are the Company's production expectations?

Delphi expects production from crude oil, natural gas and natural gas liquids to average between 8,800 to 9,000 boe/d in 2011, up ten percent from an average of 8,086 boe/d in 2010. The production mix is expected to be approximately 27 percent light oil and liquids-rich natural gas in 2011, compared to 20 percent in 2010, as the capital program focuses on light oil and liquids-rich natural gas drilling opportunities.

REVENUES

What does the Company project for crude oil and natural gas prices and the Canadian/United States exchange rate in 2011?

Natural Gas

For forecasting purposes, Delphi continues to expect a challenging natural gas market for the remainder of 2011 as a result of strong natural gas production in the United States through horizontal drilling using multi-stage fracturing technology into the shale gas plays. Delphi is expecting AECO to average $3.70 per mcf in 2011.

Crude Oil

Delphi continues to believe that oil prices will remain between U.S. $85.00 - $90.00 per barrel for the remainder of the year. For forecasting purposes, the Company believes WTI will average U.S. $93.00 per barrel in 2011.

Canadian/United States Exchange Rate

Both crude oil and natural gas prices in Canada are premised on the U.S. dollar price for each product adjusted for the Cdn/US dollar exchange rate and quality and transportation differentials. The Canadian dollar is now expected to trade slightly better than parity with the U.S. dollar in 2011. The exchange rate is influenced by many variables which will continue to result in significant volatility. Delphi has assumed an average exchange rate of $0.98 Cdn. to U.S. dollar.

Has Delphi undertaken any hedges for 2011 and 2012 to mitigate the risk of volatility in its product pricing?

In light of the low natural gas prices over the past two years and a future outlook which has resulted in the forward price curve for natural gas to decrease based on the view that there is ample supply of natural gas with the development of the shale gas plays, particularly in the United States, Delphi has become more focused on protecting the downside of prices as opposed to locking in gains to be made on unusually high prices. Currently, Delphi has hedged approximately 51 percent of its before-royalty natural gas production at a predominantly AECO based average floor price of $4.88 per mcf for the remainder of 2011. Delphi continually monitors the variables affecting the price of natural gas and crude oil in order to ensure its capital program is in line with expected funds from operations. The following natural gas hedges are in place to support the Company's cash flow.

	Oct-Dec 2011	2012
Production hedged (mmcf/d)	19.8	2.3
Percentage of natural gas production *	51%	6%
Price floor (Cdn $/mcf)	$4.88	$4.70

* based on 38.5 mmcf/d

The Company has also executed a call option at U.S. $90.00 on 600 bbls/d for January 1, 2011 to December 31, 2012. The fair value of outstanding natural gas contracts is estimated to be a gain of approximately $1.5 million with a loss of approximately $1.8 million on outstanding crude oil contracts as of September 30, 2011.

ROYALTIES

What average royalty rate does Delphi expect to pay in 2011?

The Company pays royalties to provincial governments, individuals and companies that own surface and/or mineral rights. These payments take the form of Crown, freehold and overriding royalties. Crown royalty rates for crude oil and natural gas are generally calculated on a sliding scale based on commodity prices and production rates whereas freehold and overriding royalty rates are generally a fixed percentage of revenue. Crown royalty rates can change due to price fluctuations or changes in production volumes on a well by well basis subject to minimum and maximum rates. For natural gas liquids, Crown royalty rates are a fixed percentage of revenue with the rate varying according to the nature of the product. Crown royalty credits are received from the Crown and represent the fee earned by the owners of natural gas processing infrastructure to process the Crown's royalty share of natural gas. Freehold royalties are paid on freehold lands and overriding royalties are generally payable on lands where the Company has earned an interest in the lands through a farm-in, whether the lands are Crown or freehold. Royalties are not affected by gains or losses realized through the Company's risk management program.

For 2011, Delphi expects its royalty rate, after the deduction for royalty credits, will average between 15 to 17 percent of gross revenue, excluding realized and unrealized gains or losses on financial instruments.

TRANSPORTATION EXPENSES AND OPERATING COSTS

Will Delphi be able to further reduce its costs of production in 2011?

Transportation expenses are costs incurred by the Company to transport its production volumes from the wellhead to the point of sales. In British Columbia, infrastructure is owned by Spectra Energy Corp. that enables natural gas producers to avoid facility construction in exchange for regulated gathering, processing and transmission fees. This all-in charge is included in transportation expenses.

Delphi expects its transportation expenses to be approximately $2.90 - $3.00 per boe in 2011. Transportation expenses are subject to the availability of pipeline capacity on an interruptible basis in areas of significant production growth by industry.

Operating costs have been trending downward over the past several years as Delphi focuses its capital program and achieves growth in its core areas of Bigstone, Hythe and Wapiti/Gold Creek, areas with a weighted average operating cost structure of less than $6.00 per boe. As production grows and fixed area costs are allocated over increased production volumes, the marginal cost of incremental production is expected to be less than field average operating cost. In 2011, Delphi will also realize the full year benefit of the 2010 disposition of very high operating cost production in East Central Alberta.

The costs of production may be more than expected in periods of very high industry activity causing considerable competition and rising prices for general oilfield services and equipment, however, further reductions in operating costs are anticipated resulting in expected operating costs averaging between $6.75 and $7.00 per boe in 2011.

GENERAL & ADMINISTRATIVE AND FINANCE COSTS

What are the Company's overhead costs for personnel and financing?

In 2011, Delphi anticipates its general and administrative costs, net of capitalized amounts, to be approximately $2.00 per boe. A high level of industry activity may cause an increase in general and administrative expenses due to higher than expected employee retention costs and to hire new employees and general cost inflation.

Interest costs will be dependent on market rates and credit spreads for the oil and gas sector and will be a function of the general economic conditions in Canada. If the economy is viewed as growing too fast, which may result in inflation, interest rates may be increased to slow down the pace of growth in the economy. Interest costs may also increase if cash flow from operations is less than expected and bank debt is used to fund a larger portion of the capital program than originally anticipated. Interest expense is expected to be approximately $1.75 per boe in 2011.

CAPITAL PROGRAM AND NET DEBT LEVELS

What are the Company's forecast capital expenditures and net debt levels for 2011?

In 2011, Delphi anticipates a field capital program, net of dispositions, of approximately $90.0 – 95.0 million resulting in net debt levels between $120.0 and $125.0 million by the end of 2011. Cash flow for the year is expected to be approximately $65.0 to $69.0 million resulting in a forecast net debt to cash flow ratio of approximately 1.9:1 at the end of 2011.

BUSINESS ENVIRONMENT

What external factors of the business environment did the Company have to contend with in the third quarter of 2011?

The price the Company receives for its production volumes is a significant determinant of the Company's cash flow. The table below outlines the changes in the various benchmark commodity prices and economic parameters which affect the prices received for the Company's production.

Benchmark Prices and Economic Parameters

	Three Months Ended September 30			Nine Months Ended September 30		
	2011	2010	% Change	**2011**	2010	% Change
Natural Gas						
NYMEX (US $/mmbtu)	**4.12**	4.30	(4)	**4.22**	4.58	(8)
AECO (CDN $/mcf)	**3.65**	3.54	3	**3.76**	4.12	(9)
Crude Oil						
West Texas Intermediate (US $/bbl)	**89.80**	76.17	18	**95.49**	77.64	23
Edmonton Light (CDN $/bbl)	**91.74**	74.44	23	**94.32**	76.53	23
Foreign Exchange						
Canadian to U.S. dollar	**0.98**	1.04	(6)	**0.98**	1.04	(6)
U.S. to Canadian dollar	**1.02**	0.96	7	**1.02**	0.97	5

Natural Gas

AECO averaged $3.65 per mcf in the third quarter of 2011, three percent greater than the comparative period. For the nine months ended September 30, 2011, AECO was nine percent lower than the same period of 2010. The growth in natural gas supply continues to exceed the growth in natural gas demand in North America leading to an excess supply situation and lower natural gas commodity prices.

Crude Oil

WTI averaged U.S. $89.80 per barrel in the third quarter of 2011, an increase of 18 percent over the third quarter of 2010. As a result of a narrowing basis differential, Canadian prices were 23 percent higher in the third quarter of 2011 over the comparative period of 2010. Edmonton light averaged $91.74 per barrel in the third quarter of 2011 versus $74.44 per barrel in 2010.

Canadian/United States Exchange Rate

The value of the Canadian dollar against its U.S. counterpart continued to strengthen in the second quarter of 2011 as crude oil prices breached U.S. $100.00 per barrel and the concerns over the U.S. government's total debt were raised. As a producer of crude oil, a stronger Canadian dollar has had a negative effect on the price received for production. The Cdn/US exchange rate varied from a high of $0.94 to a low near $1.04 late in the third quarter. This negative effect to the price of oil for Canadian producers was offset by a narrowing basis differential between U.S. and Canadian markets.

Industry Cost of Services

The increase in crude oil prices and the demand to drill horizontal oil and natural gas wells using multi-stage fracturing technology has resulted in drilling contractors and oilfield service companies keeping very busy. Natural gas drilling has become more focused on liquids-rich natural gas opportunities with continued strong demand for high deliverability natural gas wells in the Canadian shale gas plays, predominantly the Montney formation. Consequently, there has been pricing pressure on drilling equipment capable of completing these types of operations. Completion services have also tightened up as more and more horizontal drilling is undertaken with the intention of completing the wells using multi-stage fracturing technology.

OPERATIONAL AND FINANCIAL RESULTS

DRILLING OPERATIONS

How active was Delphi in its drilling program in the third quarter of 2011?

Capital activity in the third quarter included the drilling of 9.0 gross (6.2 net) wells. In addition, the Company carried out completion and tie-in operations on three wells drilled late in the second quarter. The capital program was delayed temporarily in July due to wet weather conditions in North West Alberta. In light of continued low natural gas prices, the Company focused its efforts on drilling light oil and liquids-rich natural gas opportunities in the quarter.

	Three Months Ended September 30, 2011		Nine Months Ended September 30, 2011	
	Gross	**Net**	**Gross**	**Net**
Liquids-rich natural gas wells	**7.0**	**4.8**	**17.0**	**13.5**
Oil wells	**2.0**	**1.4**	**8.0**	**5.6**
Total wells	**9.0**	**6.2**	**25.0**	**19.1**
Success rate (%)	**100**	**100**	**100**	**100**

CAPITAL INVESTED

How much did the Company spend in the third quarter and first nine months of 2011 and where were the capital expenditures incurred?

The Company continued to direct its capital program at its core areas in North West Alberta to take advantage of the multi-zone nature of these assets, low production operating costs and quick on-stream capability associated with owned gathering and processing infrastructure. Total capital invested in the field during the third quarter was $33.4 million as equipping and facility costs were incurred on completion and tie in operations on three wells drilled late in the second quarter and the remainder of the summer drilling program was largely completed. For the nine months ended September 30, 2011, Delphi incurred capital expenditures of $77.2 million, with approximately 74 percent directed at drilling and completion operations and 20 percent incurred on equipping and facility projects. During the quarter, the Company received proceeds on dispositions of $7.7 million, primarily from granting an overriding royalty on certain lands at Hythe for total proceeds of $7.5 million.

	Three Months Ended September 30			Nine Months Ended September 30		
	2011	2010	% Change	**2011**	2010	% Change
Land	**1,520**	2,310	(34)	**1,940**	6,143	(68)
Seismic	**15**	215	(93)	**166**	346	(52)
Drilling and completions	**27,169**	36,876	(26)	**57,237**	64,592	(11)
Equipping and facilities	**3,799**	3,404	12	**15,151**	12,266	23
Capitalized expenses	**1,387**	883	57	**2,650**	2,291	16
Other	**(534)**	106	-	**51**	876	(94)
Capital invested	**33,356**	43,794	(24)	**77,195**	86,514	(11)
Disposition of properties	**(7,702)**	4	-	**(8,038)**	(247)	3,154
Net capital invested	**25,654**	43,798	(41)	**69,157**	86,267	(20)
Acquisition of properties	**130**	2	6,400	**217**	387	(44)
Total capital invested	**25,784**	43,800	(41)	**69,374**	86,654	(20)

PRODUCTION

What factors contributed to the growth in production volumes and the success in growing oil and natural gas liquids volumes?

Production for the three months ended September 30, 2011 averaged 8,967 boe/d, representing an increase of eleven percent over the comparative period due to the successful drilling programs at Bigstone, Hythe and Wapiti/Gold Creek. With the continued low natural gas pricing, Delphi's 2011 drilling program primarily targeted opportunities in its crude oil and liquids-rich natural gas inventory to maximize netbacks. For the three months ended September 30, 2011, production growth is highlighted by a 60 percent increase in crude oil and natural gas liquids compared to the third quarter of 2010. A significant undeveloped land base, multi-zone potential and the successful application of emerging technologies continue to provide material growth opportunities in existing and new play concepts.

The Company's production portfolio for the third quarter and nine months ended September 30, 2011 was weighted 72 percent to natural gas, 15 percent to crude oil and 13 percent to natural gas liquids.

	Three Months Ended September 30			Nine Months Ended September 30		
	2011	2010	% Change	**2011**	2010	% Change
Natural gas (mcf/d)	**38,989**	39,439	(1)	**37,662**	38,780	(3)
Crude oil (bbls/d)	**1,395**	831	68	**1,282**	884	45
Natural gas liquids (bbls/d)	**1,074**	710	51	**1,154**	586	97
Total (boe/d)	**8,967**	8,114	11	**8,714**	7,933	10

Crude oil production in the third quarter was 68 percent higher than the comparative period. The increase in oil production is due to the successful horizontal drilling targeting Cardium light oil at Bigstone and the Doe Creek light oil at Hythe as well as the significant condensate volumes produced at the wellsite primarily on liquids-rich natural gas wells in the Wapiti area. In the third quarter of 2011, crude oil volumes include an average 133 bbls/d of field condensate produced from liquids-rich natural gas wells.

Natural gas liquids were 51 percent higher for the quarter primarily due to the increased natural gas liquids production in the Wapiti area where the Company has been successfully drilling multi-zone vertical wells with the Nikanassin formation as the primary target.

Natural gas production was one percent lower compared to the third quarter of 2010 due to a reduction in capital directed at natural gas opportunities.

REALIZED SALES PRICES

What were the sales prices realized by the Company for each of its products?

For the three months ended September 30, 2011, Delphi's risk management program realized a gain of $2.2 million. For the quarter, the realized gain on natural gas contracts was $0.64 per mcf with physical contracts contributing a gain of $0.20 per mcf and financial contracts contributing a gain of $0.44 per mcf. The gains were lower than the comparative periods due to the change in the forward curve for natural gas prices at the time the contracts were executed. Delphi's overall realized natural gas price was twelve percent lower in the third quarter of 2011 than the comparative period in 2010, primarily due to the reduced gains realized on natural gas contracts. For crude oil, the Company lost $1.10 per barrel on a call option as part of a cross commodity swap. The value of the call, at the time it was undertaken, was used to purchase a higher price on a natural gas contract. Realized crude oil prices were 19 percent higher in the third quarter of 2011, principally due to a 23 percent increase in the price of Canadian benchmark crude prices and an upgrade of the Company's crude quality.

	Three Months Ended September 30			Nine Months Ended September 30		
	2011	2010	% Change	**2011**	2010	% Change
AECO ($/mcf)	**3.65**	3.54	3	**3.76**	4.12	(9)
Heating content and marketing ($/mcf)	**0.35**	0.45	(22)	**0.27**	0.36	(25)
Gain on physical contracts ($/mcf)	**0.20**	0.93	(78)	**0.29**	0.89	(67)
Gain on financial contracts ($/mcf)	**0.44**	0.36	22	**0.35**	0.23	52
Realized natural gas price ($/mcf)	**4.64**	5.28	(12)	**4.67**	5.60	(17)
Edmonton Light ($/bbl)	**91.74**	74.44	23	**94.32**	76.53	23
Gain (loss) on financial contracts ($/bbl)	**(1.10)**	3.07	-	**(3.04)**	1.42	-
Quality differential ($/bbl)	**(1.12)**	(2.46)	54	**(0.89)**	(1.33)	33
Realized oil price ($/bbl)	**89.52**	75.05	19	**90.39**	76.62	18
Realized natural gas liquids price ($/bbl)	**54.59**	50.48	8	**50.45**	54.86	(8)
Total realized sales price ($/boe)	**40.78**	37.62	8	**40.49**	40.04	1

Delphi's oil production has changed from a mix of light and medium oil to predominantly light oil therefore the Company's average price for crude oil, since mid 2010, will generally fluctuate with the change in the benchmark crude oil prices. Due to field condensate being reported as oil production volumes, Delphi's realized oil price is also affected by the change in condensate prices which are generally priced slightly higher than Edmonton Light prices. With the disposition of the East Central Alberta properties in the second quarter of 2010, increased production of light oil at Bigstone and Hythe continues to high grade the Company's quality of crude oil resulting in pricing more reflective of light oil.

Natural gas liquids prices in the third quarter of 2011 were 8 percent higher than the third quarter of 2010, primarily as a result of higher prices received for propanes, butanes and condensate extracted from the natural gas stream at the natural gas processing facility, relative to the comparative period.

How do the realized natural gas prices compare to the benchmark AECO pricing?

Excluding hedges, the Company continues to receive higher than the AECO spot price on natural gas sales due to the high heating content of its natural gas production and the sale of approximately 5.5 million British thermal units (mmbtu) per day on the Alliance pipeline which is priced at the Chicago Monthly Index.

The following table outlines the premium Delphi realized on its natural gas price compared to the average quarterly AECO price due to the risk management program, quality of production and gas marketing arrangements. In years of both high and low commodity price environments, Delphi's realized sales price has been a premium to AECO.

	Sept. 30 2011	Jun. 30 2011	Mar. 31 2011	Dec. 31 2010	Sept. 30 2010	Jun. 30 2010	Mar. 31 2009	Dec. 31 2009
Natural Gas Price								
Delphi realized ($/mcf)	**4.64**	4.76	4.62	5.00	5.28	5.30	6.26	6.15
AECO average ($/mcf)	**3.65**	3.87	3.80	3.64	3.54	3.89	4.96	4.49
Premium to AECO	**27%**	23%	22%	37%	49%	36%	26%	37%
Hedging gain ($000's)	**2,306**	2,142	2,126	4,045	4,676	4,186	2,941	4,498

RISK MANAGEMENT ACTIVITIES

What is Delphi's risk management strategy and what contracts are in place to mitigate the risk of volatility?

Delphi enters into both financial and physical commodity contracts as part of its risk management program to manage commodity price fluctuations designed to ensure sufficient cash is generated to fund its capital program particularly when commodity prices are extremely volatile. For natural gas production, Delphi has hedged approximately 51 percent of its before-royalty natural gas production at a predominately AECO based average floor price of $4.88 per mcf for the remainder of 2011.

With respect to financial contracts, which are derivative financial instruments, management has elected not to use hedge accounting and consequently records the fair value of its natural gas and crude oil financial contracts on the balance sheet at each reporting period with the change in the fair value being classified as unrealized gains and losses in the statement of operations. Physical commodity sale contracts based in U.S. dollars include an embedded derivative associated with the foreign exchange rate. Due to this derivative, the changes in the fair value of these contracts are included in the statement of earnings.

The Company has fixed the price applicable to production volumes through the following contracts.

Time Period	Commodity	Type of Contract	Quantity Contracted	Contract Price ($/unit)
January 2011 – December 2011	Natural Gas	Physical	2,500 GJ/d	$3.79 fixed
January 2011 – December 2011*	Natural Gas	Financial	2,500 GJ/d	$7.14 call
January 2011 – December 2011***	Natural Gas	Financial	3,000 GJ/d	$4.00 put
January 2011 – December 2011****	Natural Gas	Physical	2,500 GJ/d	$4.12 fixed
January 2011 – December 2012**	Crude Oil	Financial	600 bbls/d	U.S. $90.00 call
April 2011 – October 2011	Natural Gas	Physical	2,000 GJ/d	$5.66 fixed
April 2011 – October 2011	Natural Gas	Physical	4,000 GJ/d	$3.80 fixed
April 2011 – October 2011	Natural Gas	Financial	2,000 GJ/d	$3.82 fixed
April 2011 – October 2011	Natural Gas	Financial	2,000 GJ/d	$3.79 fixed
April 2011 – December 2011**	Natural Gas	Financial	6,810 GJ/d	$5.69 fixed
April 2011 – December 2011	Natural Gas	Physical	2,000 GJ/d	U.S. $4.52 fixed
November 2011 – March 2012	Natural Gas	Physical	1,000 mmbtu/d	U.S. $5.14 fixed
January 2012 – December 2012***	Natural Gas	Financial	3,000 GJ/d	$4.50 call
January 2012 – December 2012****	Natural Gas	Physical	2,500 GJ/d	$4.50 call
April 2012 – October 2012	Natural Gas	Physical	1,000 mmbtu/d	U.S. $4.96 fixed
April 2012 – October 2012	Natural Gas	Physical	2,000 GJ/d	$4.06 fixed

* The Company had a natural gas put contract at $4.75 per gigajoule on 2,500 gigajoules per day for the period April 1, 2010 through October 31, 2010. This put was paid for with the sale of a natural gas call on 2,500 gigajoules per day at a price of $7.14 per gigajoule for the period January 1, 2011 through December 31, 2011.

** The Company has acquired a natural gas contract at $5.69 per gigajoule on 6,810 gigajoules per day for the period April 1, 2011 through December 31, 2011. This contract was paid for with the sale of a crude oil call on 600 barrels per day at a price of U.S. $90.00 WTI per barrel for the period January 1, 2011 through December 31, 2012.

*** The Company has acquired a natural gas put contract at $4.00 per gigajoule on 3,000 gigajoules per day for the period January 1, 2011 through December 31, 2011. This put was paid for with the sale of a natural gas call on 3,000 gigajoules per day at a price of $4.50 per gigajoule for the period January 1, 2012 through December 31, 2012.

**** The Company has acquired a natural gas contract at $4.12 per gigajoule on 2,500 gigajoules per day for the period January 1, 2011 through December 31, 2011. This contract was paid for with the sale of a natural gas call on 2,500 gigajoules per day at a price of $4.50 per gigajoule for the period January 1, 2012 through December 31, 2012.

The Company recognized an unrealized gain on its financial contracts of $2.1 million in the third quarter of 2011, primarily due to the crude oil call option. The fair values of these contracts are based on an approximation of the amounts that would have been paid to or received from counterparties to settle the contracts outstanding at the end of the period having regard to forward prices and market values provided by independent sources. Due to the inherent volatility in commodity prices, actual amounts realized may differ from these estimates.

The Company accounts for its Canadian dollar physical sales contracts, which were entered into and continue to be held for the purpose of delivery of production, in accordance with its expected sale requirements as executory contracts on an accrual basis rather than as non-financial derivatives.

REVENUE

How do revenues in the third quarter of 2011 compare to 2010 and what factors contributed to the change?

For the three months ended September 30, 2011, Delphi generated revenue of $32.2 million representing a 21 percent increase over the comparative quarter of 2010. The composition of revenue by product for the nine months ended September 30, 2011 changed significantly versus the comparative period. For the nine months ended September 30, 2011, natural gas revenues accounted for 47 percent of total revenue versus 68 percent in the comparative period in 2010. Crude oil and natural gas liquids represented 52 percent of revenue in 2011 versus 32 percent in the same period in 2010. The change in mix is a combination of prices received for the products whereby realized natural gas prices decreased while crude oil prices increased and the growth in production volume of the products.

The risk management program associated with natural gas and crude oil pricing generated revenue of $5.5 million in the first nine months of 2011. For twelve consecutive quarters, Delphi has received a significant premium to AECO pricing primarily due to the success of the risk management program.

	Three Months Ended September 30			Nine Months Ended September 30		
	2011	2010	% Change	**2011**	2010	% Change
Natural gas	**14,330**	14,493	(1)	**41,450**	47,504	(13)
Natural gas physical contract gains	**716**	3,385	(79)	**2,957**	9,402	(69)
Crude oil	**11,631**	5,503	111	**32,710**	18,147	80
Natural gas liquids	**5,395**	3,297	64	**15,900**	8,776	81
Sulphur	**122**	(124)	-	**755**	151	400
Total	**32,194**	26,554	21	**93,772**	83,980	12

ROYALTIES

What were royalty costs in the third quarter of 2011?

In the third quarter of 2011, the Company paid Crown, freehold and gross overriding royalties. Crown royalties of $5.6 million were partially offset by $1.4 million of royalty credits for processing the Crown's share of natural gas. The net amount of $4.2 million represents 78 percent of the total royalties paid in the quarter compared to 62 percent in the same quarter of 2010. The net Crown royalties increased in 2011 compared to 2010 primarily as a result of higher crude oil commodity prices in 2011 and the Company's significant increase in crude oil and natural gas liquids production.

Gross overriding royalties represented 23 percent of total royalties in the third quarter of 2011 compared to 38 percent in 2010. The increase in gross overriding royalties is primarily a result of higher crude oil prices and higher production volumes encumbered by gross overriding royalties.

	Three Months Ended September 30			Nine Months Ended September 30		
	2011	2010	% Change	**2011**	2010	% Change
Crown royalties	**5,650**	3,400	66	**14,793**	12,427	19
Royalty credits	**(1,418)**	(1,557)	(9)	**(4,207)**	(4,374)	(4)
Crown royalties – net	**4,232**	1,843	130	**10,586**	8,053	31
Freehold royalties	**(64)**	5	-	**(11)**	170	-
Gross overriding royalties	**1,276**	1,145	11	**3,909**	3,303	18
Total	**5,444**	2,993	82	**14,484**	11,526	26
Per boe	**6.60**	4.01	65	**6.09**	5.32	14

What were the average royalty rates paid on production in the nine months ended September 30, 2011?

The average royalty rates were higher than the comparative period. Crown royalty rates were 8 percent higher primarily as a result of increased crude oil and natural gas liquids production in 2011 compared to 2010. Overriding royalties decreased primarily as a result of a decrease in production from wells encumbered by an overriding royalty.

	Three Months Ended September 30			Nine Months Ended September 30		
	2011	2010	% Change	**2011**	2010	% Change
Crown rate – net of royalty credits	**13.4%**	8.0%	68	**11.7%**	10.8%	8
Gross overriding rate	**3.9%**	4.9%	(20)	**4.3%**	4.4%	(2)
Average rate	**17.3%**	12.9%	34	**16.0%**	15.5%	3

The royalty rate calculations above exclude gains or losses on risk management activities from revenue as the denominator.

OPERATING EXPENSES

How has the Company been able to reduce its operating expenses in 2011 as compared to 2010?

Production costs for the three months ended September 30, 2011, increased seven percent over the comparative period and were five percent lower for the nine months ended September 30, 2011. The Company accumulated new and additional infrastructure in its core areas during 2009 which allows for lower per boe operating costs as production volumes continue to increase. Total operating costs in the third quarter of 2011 were $6.85 per boe which represents an 8 percent decrease over the $7.44 per boe experienced in 2010. For the nine months ended September 30, 2011, total operating costs per boe were 16 percent lower than the comparative period of 2010. The decrease is attributed to lower field operating costs, the disposition of the East Central Alberta properties in the second quarter of 2010 as well as increased volumes from the cost efficient core areas of Hythe, Wapiti/Gold Creek and Bigstone.

The Company earns processing income on third party production volumes going through facilities owned by Delphi. The processing income represents a reduction of the Company's costs to operate these facilities and hence is deducted in determining operating expenses. Processing income indicates the Company has excess capacity at its facilities which it can access to handle growth in its production volumes. Processing income was higher in the three and nine months ended September 30, 2011 than the comparative period of 2010 by 53 and 20 percent respectively, partially due to company operated plant equalizations.

	Three Months Ended September 30			Nine Months Ended September 30		
	2011	2010	% Change	**2011**	2010	% Change
Production costs	**6,536**	6,130	7	**18,219**	19,157	(5)
Processing income	**(885)**	(578)	53	**(2,164)**	(1,810)	20
Total	**5,651**	5,552	2	**16,055**	17,347	(7)
Per boe	**6.85**	7.44	(8)	**6.75**	8.01	(16)

TRANSPORTATION EXPENSES

	Three Months Ended September 30			Nine Months Ended September 30		
	2011	2010	% Change	**2011**	2010	% Change
Total	**2,668**	2,149	24	**7,149**	6,819	5
Per boe	**3.23**	2.88	12	**3.01**	3.15	(4)

What factors contributed to the change in transportation costs in 2011?

On a per boe basis, transportation costs for the three months ended September 30, 2011, increased by 12 percent over the comparative period and were four percent lower for the nine months ended September 30, 2011. The increase in transportation costs per boe in the quarter is primarily due to increased trucking costs to haul light oil volumes to the sales terminal. For the nine months ended September 30, 2011, transportation expenses per boe are lower by 4 percent primarily due to the increase in production volumes of eleven percent versus a five percent increase in transportation costs.

GENERAL AND ADMINISTRATIVE

	Three Months Ended September 30			Nine Months Ended September 30		
	2011	2010	% Change	**2011**	2010	% Change
General and administrative costs	**2,742**	2,568	7	**9,636**	8,470	14
Overhead recoveries	**(493)**	(492)	-	**(1,318)**	(1,442)	(9)
Salary allocations	**(919)**	(781)	18	**(3,491)**	(2,314)	51
Net	**1,330**	1,295	3	**4,827**	4,714	2
Per boe	**1.61**	1.73	(7)	**2.03**	2.18	(7)

How do general and administrative costs in 2011 compare to 2010?

An increase in personnel costs due to an expansion of the technical teams were offset by increased salary allocations and growth in production volumes resulting in costs per boe decreasing over the comparative periods. On a per boe basis, general and administrative (G&A) costs were down by seven percent in the third quarter of 2011 compared to the third quarter of 2010. On the same comparative basis for the nine months ended September 30, G&A costs per boe were also down seven percent. Delphi is committed to delivering strong growth and believes a strong team is paramount to achieve this goal.

SHARE-BASED COMPENSATION

What is share-based compensation expense?

Share-based compensation expense is the amortization over the vesting period of the fair value of stock options granted to employees, directors and key consultants of the Company. The fair value of all options granted is estimated at the date of grant using the Black-Scholes option pricing model.

	Three Months Ended September 30			Nine Months Ended September 30		
	2011	2010	% Change	**2011**	2010	% Change
Share-based compensation	**678**	499	35	**1,213**	1,165	4
Capitalized costs	**(588)**	(115)	411	**(626)**	(337)	86
Net	**90**	384	(77)	**587**	828	(29)
Per boe	**0.11**	0.51	(78)	**0.25**	0.38	(34)

The share-based non-cash compensation expense for the three months ended September 30, 2011, increased 35 percent over the comparative period. The increase is attributed to the issuance of options in the second quarter. During the three months ended September 30, 2011, Delphi capitalized $0.6 million of share-based compensation associated with exploration and development activities.

FINANCE COSTS

How do the costs of borrowing compare against the comparative period?

For the three and nine months ended September 30, 2011, interest costs were 21 percent and 6 percent higher than the comparative period, respectively, primarily due to the increase in the Canadian prime interest rates.

	Three Months Ended September 30			Nine Months Ended September 30		
	2011	2010	% Change	**2011**	2010	% Change
Interest	**1,337**	1,103	21	**4,020**	3,774	6
Accretion	**105**	118	(11)	**384**	385	-
Total	**1,442**	1,221	18	**4,404**	4,159	6
Interest per boe	**1.62**	1.48	9	**1.69**	1.74	(3)
Accretion per boe	**0.13**	0.16	(19)	**0.16**	0.18	(11)

During 2009, the Company converted $80.0 million of its outstanding long term debt from prime-based loans to bankers' acceptances. At September 30, 2011, the bankers' acceptances have terms ranging from 90 to 182 days and a weighted average effective interest rate of 4.22 percent over the term.

What is accretion expense and how did this expense for 2011 compare to 2010?

The accretion of decommissioning obligations is an expense that relates to the passing of time until the Company estimates it will retire its assets and restore the asset locations to a condition which meets or exceeds environmental standards. Due to the long term nature of certain assets of the Company, this accretion expense is estimated to extend over a term of three to 20 years. The Company used a risk-free interest rate of 2.2 percent for the purpose of calculating the fair value of its decommissioning obligations and hence the accretion expense. The accretion expense for the three months ended September 30, 2011 decreased 11 percent over the comparative period.

DEPLETION AND DEPRECIATION

Has the Company's depletion and depreciation rate and expense changed in the third quarter of 2011 compared to the comparative period?

Depletion and depreciation per boe for the three and nine months ended September 30, 2011 increased ten percent and eight percent, respectively, over the comparative period. With continued drilling success at Bigstone, Hythe and Wapiti/Gold Creek, Delphi has been able to add proved plus probable reserves at a cost very similar to the Company's current depletion rate. The increase in total depletion and depreciation was primarily a result of increased production volumes.

In the first nine months ended September 30, 2010, the Company recorded an impairment loss of $35.5 million on several non-core cash generating units as a result of declining natural gas prices.

	Three Months Ended September 30			Nine Months Ended September 30		
	2011	2010	% Change	**2011**	2010	% Change
Depletion and depreciation	**11,585**	10,579	10	**33,708**	31,088	8
Impairment loss	**-**	30,500	-	**-**	35,500	(100)
Total	**11,585**	41,079	(72)	**33,708**	66,588	(49)
Per boe	**14.04**	55.03	(74)	**14.17**	30.75	(54)

INCOME TAXES

What was the affect on deferred income taxes as a result of the earnings for the period?

The provision for deferred income taxes in the financial statements for the three and nine months ended September 30, 2011 was an expense of $2.7 million and $5.1 million, respectively. Delphi does not anticipate it will be cash taxable before 2014.

	Three Months Ended September 30			Nine Months Ended September 30		
	2011	2010	% Change	**2011**	2010	% Change
Current	**-**	-	-	**-**	-	-
Deferred	**2,710**	(7,063)	-	**5,071**	(5,489)	-
Total	**2,710**	(7,063)	-	**5,071**	(5,489)	-
Per boe	**3.28**	(9.46)	-	**2.13**	(2.53)	-

FUNDS FROM OPERATIONS

What are funds from operations and why is it a key performance measure?

Funds from operations is a non-IFRS measure that has been defined by the Company as net earnings (loss) plus the add back of non-cash items (depletion and depreciation, accretion, stock-based compensation, loss on dispositions, deferred income taxes and unrealized gain (loss) on the fair value of financial instruments) and excludes the accretion of long term debt, change in non-cash working capital related to operating activities and expenditures on decommissioning obligations. Delphi uses this cash flow measure to analyze performance and considers it a key measure as it demonstrates the Company's ability to generate the cash necessary to fund future capital investments to grow the Company's value for the shareholders and to repay debt.

How do funds from operations in the third quarter of 2011 compare to 2010?

For the three months ended September 30, 2011, funds from operations were $17.2 million ($0.15 per basic share) compared to $15.0 million ($0.13 per basic share) in the comparative period. The increase in funds from operations is primarily a result of an increase in production volumes, a reduction in operating costs and higher realized sales price per boe.

	Three Months Ended September 30			Nine Months Ended September 30		
	2011	2010	% Change	**2011**	2010	% Change
Net earnings (loss)	**4,058**	(20,472)	-	**10,777**	(18,728)	-
Non-cash items:						
Depletion and depreciation	**11,585**	41,079	(72)	**33,708**	66,588	(49)
Accretion of decommissioning obligations	**105**	118	(11)	**384**	385	-
Loss on dispositions	**741**	-	100	**405**	-	100
Unrealized (gain) loss on risk management activities	**(2,076)**	956	-	**(1,141)**	(1,282)	(11)
Stock-based compensation expense	**90**	384	(76)	**587**	828	(29)
Exploration and evaluation	**-**	(14)	100	**-**	242	(100)
Deferred income taxes	**2,710**	(7,063)	-	**5,071**	(5,489)	-
Funds from operations	**17,213**	14,988	15	**49,791**	42,544	17

How do funds from operations compare to cash flow from operating activities in the financial statements?

Funds from operations reflect two primary differences from the IFRS term cash flow from operating activities shown on the financial statements. These differences are expenditures incurred for decommissioning obligations, changes in non-cash operating working capital and accretion of long term debt. The following table is a reconciliation of funds from operations to cash flow from operating activities for the three and nine months ended September 30, 2011 and 2010.

	Three Months Ended September 30			Nine Months Ended September 30		
	2011	2010	% Change	**2011**	2010	% Change
Funds from operations: Non-IFRS	**17,213**	14,988	15	**49,791**	42,544	17
Accretion of long term debt	**65**	-	100	**(340)**	-	(100)
Change in non-cash working capital	**3,363**	(4,741)	-	**1,715**	(2,973)	-
Cash flow from operating activities: IFRS	**20,641**	10,247	101	**51,166**	39,571	29

NET EARNINGS

What factors contributed to the earnings in 2011?

For the three and nine months ended September 30, 2011, Delphi recorded net earnings of $4.1 million ($0.03 per basic share) and $10.8 million ($0.09 per basic share), respectively. Net earnings for the third quarter were achieved primarily due to cash netbacks of $20.87 per boe on production being greater than an average depletion rate of $14.04 per boe. Net earnings were reduced by the negative impact of stock-based compensation, accretion on decommissioning liabilities and future income taxes. These non-cash items represent the majority of the significant difference between funds from operations and net earnings.

NETBACK ANALYSIS

How do Delphi's netbacks achieved in the third quarter of 2011 compare to the same period in the prior year?

For the nine months ended September 30, 2011, the Company's cash netbacks were higher by 7 percent principally due to lower operating and transportation expenses. The Company strives for an operating netback in the $22.00 to $25.00 per boe range and a cash netback of $20.00 per boe in the current commodity price environment.

Delphi's production is predominantly natural gas and therefore Delphi's operating and cash netbacks are primarily driven by the price received for natural gas. The Company is focused on increasing its light oil and natural gas liquids percentage of total production volumes to further strengthen its cash netback per boe.

	Three Months Ended September 30			Nine Months Ended September 30		
	2011	2010	% Change	**2011**	2010	% Change
Barrels of oil equivalent ($/boe)						
Realized sales price	**40.78**	37.62	8	**40.49**	40.04	1
Royalties	**6.60**	4.01	65	**6.09**	5.32	14
Operating expenses	**6.85**	7.44	(8)	**6.75**	8.01	(16)
Transportation	**3.23**	2.88	12	**3.01**	3.15	(4)
Operating netback	**24.10**	23.29	3	**24.64**	23.56	5
General and administrative expenses	**1.61**	1.73	(7)	**2.03**	2.18	(7)
Interest	**1.62**	1.48	9	**1.69**	1.74	(3)
Cash netback	**20.87**	20.08	4	**20.92**	19.64	7
Unrealized (gain)loss on financial contracts	**(2.51)**	1.29	-	**(0.49)**	(0.60)	(18)
Stock-based compensation expense	**0.11**	0.51	(78)	**0.25**	0.38	(34)
Depletion and depreciation	**14.04**	55.03	(74)	**14.17**	30.75	(54)
Accretion	**0.13**	0.16	(19)	**0.16**	0.18	(11)
Loss on dispositions	**0.90**	-	100	**0.17**	-	100
Exploration and evaluation	**-**	(0.02)	100	**-**	0.11	100
Deferred income taxes	**3.28**	(9.46)	-	**2.13**	(2.53)	-
Net earnings (loss)	**4.92**	(27.43)	-	**4.53**	(8.65)	-

SELECTED INFORMATION

Over the past two years, how has Delphi performed and what significant factors contributed to the results?

Over the last eight quarters, average production has grown from 6,773 boe/d to 8,967 boe/d. Production for the last eight quarters reflects the following events. With crude oil and natural gas prices going in opposite directions through 2009, the capital program in the second half of 2009 was geared toward drilling for crude oil while acquiring strategic natural gas properties and infrastructure. The Company completed four natural gas property and infrastructure acquisitions in the Deep Basin of North West Alberta in the latter half of 2009. Continued drilling success in 2010 focused on light oil and liquids-rich natural gas opportunities resulted in record fourth quarter and annual production of 8,539 boe/day and 8,086 boe/day, respectively. The 2010 average production represents growth of 19 percent over 2009. In the first quarter of 2011, production was 8,259 boe/d as a result of natural declines in production and an outage at a non-operated processing facility resulting in the shut-in of 550 boe/d for 22 days in the quarter. In the second quarter of 2011, production was 8,906 boe/d as a result of a successful winter drilling program focused on crude oil and liquids rich natural gas opportunities. Production for the third quarter of 2011 averaged 8,967 boe/d.

Over the past two years, the changes in revenue and funds from operations from quarter to quarter primarily reflect the increased production volumes achieved and the volatility of commodity prices.

Natural gas prices over the past two years have generally reflected the cyclical nature of demand. Higher prices have been realized in the winter months, reflecting demand for heating with lower prices through the summer months as production is placed in storage for the upcoming heating season demand. In 2009, reduced heating and industrial demand due to the global economic crisis caused natural gas prices to decrease further as a result of concerns over excess supply relative to demand. The average spot price for AECO in 2009 was $3.96 per mcf, the lowest average price in ten years. The average spot price for AECO in 2010 increased only one percent to $4.00 per mcf. In 2011, the average spot price for AECO has been $3.76 per mcf. Crude oil prices had recovered to over U.S. $80.00 per barrel by the end of 2009 from a low earlier in the year of U.S. $33.98 per barrel. In 2010, crude oil averaged U.S. $79.55, which was a 28 percent increase over the comparative period in 2009. In the first half of 2011, crude oil prices increased exceeding U.S. $100 but have withdrawn in the third quarter, averaging U.S. $89.80. The average oil price was U.S. $95.49 for the first nine months of 2011.

Net earnings of the Company are primarily driven by the difference between the cash flow netback realized per boe of production versus the Company's depletion, depreciation and amortization ("DD&A") rate. The Company continues to reduce its DD&A rate by finding and developing reserves at a cost less than the average DD&A rate. Overall finding and development ("F&D") costs were $9.21 per proved plus probable boe in 2009 and $14.91 per proved plus probable boe in 2010.

The following table sets forth certain information of the Company for the past eight consecutive quarters outlining this performance.

	IFRS	*IFRS*	*IFRS*	*IFRS*	*IFRS*	*IFRS*	*IFRS*	*GAAP*
	Sept. 30 2011	Jun. 30 2011	Mar. 31 2011	Dec. 31 2010	Sep. 30 2010	Jun. 30 2010	Mar. 31 2010	Dec. 31 2009
Production								
Natural gas (mcf/d)	**38,989**	37,460	36,509	38,918	39,439	38,540	38,349	34,626
Oil (bbls/d)	**1,395**	1,346	1,102	1,147	831	1,074	745	630
Natural gas liquids (bbls/d)	**1,074**	1,317	1,072	906	710	538	508	487
Barrels of oil equivalent (boe/d)	**8,967**	8,906	8,259	8,539	8,114	8,035	7,645	6,888
Financial								
($ thousands except per unit amounts)								
Petroleum and natural gas revenue	**32,194**	32,678	28,900	29,792	26,554	27,970	29,519	26,297
Funds from operations	**17,213**	17,517	15,061	17,603	14,988	12,507	15,049	14,218
Per share – basic	**0.15**	0.15	0.13	0.16	0.13	0.12	0.15	0.14
Per share – diluted	**0.14**	0.15	0.13	0.16	0.13	0.12	0.15	0.14
Net earnings (loss)	**4,058**	5,757	962	1,744	(20,472)	(131)	1,613	1,386
Per share – basic	**0.03**	0.05	0.01	0.02	(0.18)	-	0.02	0.02
Per share – diluted	**0.03**	0.05	0.01	0.02	(0.18)	-	0.02	0.02

LIQUIDITY AND CAPITAL RESOURCES

Share Capital

What has been the market activity in the Company's common shares?

At September 30, 2011, the Company had 117.9 million common shares outstanding (December 31, 2010 – 112.8 million). The common shares of Delphi trade on the TSX under the symbol DEE. The following table summarizes outstanding share data for the three and nine months ended September 30, 2011.

	Three Months Ended September 30, 2011	Nine Months Ended September 30, 2011
Weighted Average Common Shares		
Basic	117,660	116,204
Diluted	119,236	118,255
Trading Statistics [1]		
High	2.51	2.89
Low	1.50	1.50
Average daily volume	350,743	523,636

[1] Trading statistics based on closing price

How many common shares and stock options are currently outstanding?

As at October 31, 2011, the Company had 117.9 million common shares outstanding and 10.8 milllion stock options outstanding. The stock options have an average exercise price of $1.89 per option.

Sources and Uses of Funds

	Three Months Ended September 30, 2011	Nine Months Ended September 30, 2011
Sources:		
Funds from operations	**17,213**	**49,791**
Disposition of petroleum and natural gas properties	**7,702**	**8,038**
Issue of flow-through common shares, net of issue costs	**-**	**8,928**
Exercise of stock options	**624**	**2,424**
Change in non-cash working capital	**20,880**	**10,542**
	46,419	**79,723**
Uses:		
Cash and cash equivalents	**(3,991)**	**(5,842)**
Capital expenditures	**(33,356)**	**(77,195)**
Accretion of long term debt	**65**	**(340)**
Acquisition of petroleum and natural gas properties	**(130)**	**(217)**
	(37,412)	**(83,594)**
Change in long term debt	**(9,007)**	**3,871**

Bank Debt plus Working Capital Deficiency (Net Debt)

How much bank debt was outstanding on September 30, 2011?

At September 30, 2011, the Company had $79.6 million outstanding in the form of bankers' acceptances, $28.0 million drawn under Canadian-based prime loans and a working capital deficiency of $8.7 million for total net debt of $116.3 million excluding the fair value of financial instruments.

What are the Company's credit facilities and when is the next scheduled review of the borrowing base?

The Company has a $145.0 million extendible revolving term credit facility with a syndicate of Canadian chartered banks, subject to the banks' semi-annual valuation of the Company's crude oil and natural gas properties. The facility is a 364 day committed facility available on a revolving basis until May 28, 2012 at which time it may be extended at the lenders' option. If the revolving period is not extended, the undrawn portion of the facility will be cancelled and the amount outstanding will convert to a 365 day non-revolving term facility. The amounts outstanding under the non-revolving facility are required to be repaid at the end of the non-revolving term being May 28, 2013. The non-extension provisions are applicable to the lenders on an individual basis.

Interest payable on amounts drawn under the facility is at the prevailing bankers' acceptance rates plus stamping fees, lenders' prime rate, US base rate or LIBOR plus the applicable margins, depending on the form of borrowing by the Company. The applicable margins and stamping fees are based on a sliding scale pricing grid tied to the Company's trailing debt to annualized quarterly cash flow ratio: from a minimum of the bank's prime rate or US base rate plus 1.25 percent to a maximum of the bank's prime rate or US base rate plus 4.25 percent or from a minimum of bankers' acceptances rate plus a stamping fee of 2.25 percent to a maximum of bankers' acceptances rate plus a stamping fee of 4.25 percent.

Contractual Obligations

Does the Company have any contractual obligations as of September 30, 2011 that will require funding in future years?

The Company is committed to future minimum payments for natural gas transmission and processing and operating leases on compression equipment. The Company also has a lease for office space in Calgary, Alberta.

The future minimum commitments over the next five years are as follows:

	2011	2012	2013	2014	2015
Gathering, processing and transmission	1,010	4,303	3,609	3,077	3,046
Office and equipment lease	271	797	394	-	-
Total	1,281	5,100	4,003	3,077	3,046

GUARANTEES AND OFF-BALANCE SHEET ARRANGEMENTS

Does Delphi have any outstanding guarantees on behalf of third parties or any off-balance sheet arrangements which could lead to liabilities in the future?

Delphi has not entered into any guarantees or off-balance sheet arrangements. Certain lease agreements entered into in the normal course of operations could be considered off-balance sheet arrangements, however, all leases are operating leases with lease payments charged to operating expenses or general and administrative expenses on a monthly basis according to the lease.

CRITICAL ACCOUNTING ESTIMATES

In preparing the Company's consolidated financial statements, is Delphi required to make estimates or assumptions about future events?

The interim consolidated financial statements have been prepared in conformity with IFRS which requires management to make judgments, estimates and assumptions that affect the application of accounting policies and the reported amounts of assets, liabilities, shareholders' equity, revenue and expenses. Actual results may differ from these estimates.

Estimates and their underlying assumptions are reviewed on an ongoing basis. Delphi attempts to mitigate this risk by employing individuals with the appropriate skill set and knowledge to make reasonable estimates, developing internal control systems and comparing past estimates to actual results. Revisions to accounting estimates are recognized in the period in which the estimates are revised and in any future periods affected.

In preparing interim consolidated financial statements, the significant judgments made by management in applying the Company's accounting policies and the key sources of estimation uncertainty are expected to be the same as those to be applied in the first annual IFRS financial statements. These judgments, estimates and assumptions that have the most significant effect on the amounts recognized in the consolidated financial statements are included in the following:

i) valuation of financial instruments;
ii) valuation of exploration and evaluation assets;
iii) valuation of property, plant and equipment;
iv) measurement of decommissioning obligations; and
v) measurement of share-based compensation.

Estimates of proved plus probable reserves have an effect on a number of the areas referred to above, in particular, the valuation of property, plant and equipment and the calculation of depletion and depreciation.

NEW ACCOUNTING STANDARDS

Are there any new accounting standards which the Company has had to adopt and comply with?

International Financial Reporting Standards (IFRS)

The Company adopted IFRS effective January 1, 2011. As a result, the Company's financial results for the third quarter ended September 30, 2011 and comparative periods are reported under IFRS while selected historical data prior to 2010 continues to be reported under previous Canadian GAAP. Refer to note 7 of the consolidated interim financial statements of the Company for the affects of the transition to IFRS.

In November 2009, the International Accounting Standards Board ("IASB") published IFRS 9, "Financial Instruments, which covers the classification and measurement of financial assets as part of its project to replace IAS 39, "Financial Instruments: Recognition and Measurement." In October 2010, the requirements for classifying and measuring financial liabilities were added to IFRS 9. Under this guidance, entities have the option to recognize financial liabilities at fair value through earnings. If this option is elected, entities would be required to reverse the portion of the fair value change due to a company's own credit risk out of earnings and recognize the change in other comprehensive income. IFRS 9 is effective for the Company on January 1, 2013. Early adoption is permitted and the standard is required to be applied retrospectively. The Company is currently evaluating the impact of adopting IFRS 9.

In May 2011, the International Accounting Standards Board published IFRS 11, “Joint Arrangements” which carves out certain jointly controlled entities, now called joint ventures, from IAS 31 “Interests in Joint Ventures” and removes the choice of using the equity method or proportionate consolidation when accounting for these joint ventures. The equity method must now always be used. IFRS 11 is effective for the Company on January 1, 2013. The Company is currently evaluating the impact of adopting IFRS 11.

In May 2011, the International Accounting Standards Board published IFRS 13, “Fair Value Measurement” which defines fair value, establishes a framework for measuring fair value and sets out disclosure requirements for fair value measurements. IFRS 13 is effective for the Company on January 1, 2013. The Company is currently evaluating the impact of adopting IFRS 13.

CORPORATE GOVERNANCE

Disclosure Controls and Procedures and Internal Controls over Financial Reporting

Disclosure controls and procedures are designed to ensure that information required to be disclosed by the Company is accumulated and communicated to the issuer's management, including its President and Chief Executive Officer and Vice President, Finance and Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure. The Company’s President and Chief Executive Officer and Vice President, Finance and Chief Financial Officer have concluded that the Company’s disclosure controls and procedures are effective and provide a reasonable level of assurance that information required to be disclosed by the Company is recorded, processed, summarized and reported within the time periods specified.

The Company notes that while it believes the disclosure controls and procedures and internal controls over financial reporting provide a reasonable level of assurance that they are effective, it does not expect that the disclosure controls and procedures and internal controls will prevent all errors and fraud. A control system is designed to provide reasonable, not absolute, assurance that the objectives of the control system are met. There were no changes made to the disclosure controls and procedures or internal controls over financial reporting as a result of the transition to IFRS.

ADDITIONAL INFORMATION

Where is additional information about Delphi available?

Additional information about Delphi is available on the Canadian Securities Administrators’ System for Electronic Distribution and Retrieval (SEDAR) at www.sedar.com, at the Company’s website at www.delphienergy.ca or by contacting the Company at Delphi Energy Corp. Suite 300, 500 – 4th Avenue S.W., Calgary, Alberta, T2P 2V6 or by e-mail at info@delphienergy.ca.

DELPHI ENERGY CORP.

Consolidated Statements of Financial Position

(thousands of dollars)	**September 30 2011**	December 31 2010
(unaudited)		
Assets		
Current assets		
Cash	**9,881**	4,039
Accounts receivable	**23,948**	17,897
Prepaid expenses and deposits	**2,801**	3,426
Fair value of financial instruments	**1,521**	2,080
	38,151	27,442
Exploration and evaluation assets (Note 4)	**5,425**	2,787
Property, plant and equipment (Note 5)	**392,962**	357,458
Total assets	**436,538**	387,687
Liabilities		
Current liabilities		
Accounts payable and accrued liabilities	**45,334**	28,416
Fair value of financial instruments	**1,245**	-
	46,579	28,416
Other liability	**283**	-
Long term debt	**107,581**	105,000
Decommissioning obligations	**19,870**	17,232
Fair value of financial instruments	**582**	3,527
Deferred income taxes	**22,140**	16,552
	197,035	170,727
Shareholders' Equity		
Share capital (Note 6)	**248,203**	236,382
Contributed surplus	**11,932**	11,987
Deficit	**(20,632)**	(31,409)
Total shareholders' equity	**239,503**	216,960
Total liabilities and shareholders' equity	**436,538**	387,687

See accompanying notes to the interim consolidated financial statements.

DELPHI ENERGY CORP.

Consolidated Statements of Earnings (Loss) and Comprehensive Earnings (Loss)

(thousands of dollars, except per share amounts)	**Three Months Ended September 30** **2011**	2010	**Nine Months Ended September 30** **2011**	2010
(unaudited)		(Note 7)		(Note 7)
Revenue				
Crude oil and natural gas sales	**32,194**	26,554	**93,772**	83,980
Royalties	**(5,444)**	(2,993)	**(14,484)**	(11,526)
	26,750	23,561	**79,288**	72,454
Realized gain on financial instruments	**1,449**	1,526	**2,554**	2,744
Unrealized gain (loss) on financial instruments	**2,076**	(956)	**1,141**	1,282
	30,275	24,131	**82,983**	76,480
Expenses				
Operating	**5,651**	5,552	**16,055**	17,347
Transportation	**2,668**	2,149	**7,149**	6,819
Exploration and evaluation	**-**	(14)	**-**	242
General and administrative	**1,330**	1,295	**4,827**	4,714
Share-based compensation (Note 6)	**90**	384	**587**	828
Loss on dispositions	**741**	-	**405**	-
Depletion and depreciation (Note 5)	**11,585**	41,079	**33,708**	66,588
	22,065	50,445	**62,731**	96,538
Finance costs	**1,442**	1,221	**4,404**	4,159
Earnings (loss) before taxes	**6,768**	(27,535)	**15,848**	(24,217)
Taxes				
Deferred income taxes (reduction)	**2,710**	(7,063)	**5,071**	(5,489)
Net earnings (loss) and comprehensive earnings (loss)	**4,058**	(20,472)	**10,777**	(18,728)
Net earnings (loss) per share (Note 6)				
Basic	**0.03**	(0.18)	**0.09**	(0.18)
Diluted	**0.03**	(0.18)	**0.09**	(0.18)

See accompanying notes to the interim consolidated financial statements.

DELPHI ENERGY CORP.

Consolidated Statements of Changes in Shareholders' Equity
For the nine months ended September 30, 2011 and 2010

(thousands of dollars) (unaudited)	**Share Capital**	**Contributed Surplus**	**Deficit**	**Total Shareholders' Equity**
Balance as at January 1, 2010	206,382	11,027	(14,425)	202,984
Net earnings (loss)	-	-	(18,728)	(18,728)
Issue of common shares	30,250	-	-	30,250
Share issue costs	(1,966)	-	-	(1,966)
Tax effect of share issue costs	523	-	-	523
Issued on exercise of options	673	-	-	673
Share-based compensation on exercise of options	361	(361)	-	-
Share-based compensation expense	-	828	-	828
Share-based compensation capitalized	-	331	-	331
Balance as at September 30, 2010	236,223	11,825	(33,153)	214,895

(thousands of dollars)	**Share Capital**	**Contributed Surplus**	**Deficit**	**Total Shareholders' Equity**
Balance as at December 31, 2010	236,382	11,987	(31,409)	216,960
Net earnings	-	-	10,777	10,777
Issue of flow-through common shares	8,160	-	-	8,160
Share issue costs	(32)	-	-	(32)
Issued on exercise of options	2,424	-	-	2,424
Share-based compensation on exercise of options	1,269	(1,269)	-	-
Share-based compensation expense	-	587	-	587
Share-based compensation capitalized	-	627	-	627
Balance as at September 30, 2011	**248,203**	**11,932**	**(20,632)**	**239,503**

See accompanying notes to the interim consolidated financial statements.

DELPHI ENERGY CORP.

Consolidated Statements of Cash Flows

(thousands of dollars)	Three Months Ended September 30 **2011**	Three Months Ended September 30 2010	Nine Months Ended September 30 **2011**	Nine Months Ended September 30 2010
(unaudited)				
Cash flow from (used in) operating activities				
Net earnings (loss)	**4,058**	(20,472)	**10,777**	(18,728)
Add non-cash items:				
Depletion and depreciation	**11,585**	41,079	**33,708**	66,588
Accretion of decommissioning obligations	**105**	118	**384**	385
Accretion of long term debt	**65**	-	**(340)**	-
Share-based compensation	**90**	384	**587**	828
Loss on dispositions	**741**	-	**405**	-
Expensing of exploration and evaluation costs	**-**	(14)	**-**	242
Unrealized loss (gain) on financial instruments	**(2,076)**	956	**(1,141)**	(1,282)
Deferred income taxes	**2,710**	(7,063)	**5,071**	(5,489)
Change in non-cash working capital	**3,363**	(4,741)	**1,715**	(2,973)
	20,641	10,247	**51,166**	39,571
Cash flow from (used in) financing activities				
Issue of common shares, net of issue costs	**-**	16	**-**	28,284
Issue of flow-through common shares, net of issue costs	**-**	-	**8,928**	-
Exercise of stock options	**624**	66	**2,424**	673
Increase (decrease) in long term debt	**(9,007)**	-	**3,871**	(1,100)
	(8,383)	82	**15,223**	27,857
Cash flow available for investing activities	**12,258**	10,329	**66,389**	67,428
Cash flow from (used in) investing activities				
Additions to exploration and evaluation assets	**(1,669)**	(226)	**(2,638)**	(2,295)
Additions to property, plant and equipment	**(31,687)**	(43,568)	**(74,557)**	(84,219)
Proceeds on the disposition of petroleum and natural gas properties	**7,702**	(4)	**8,038**	247
Expensing of exploration and evaluation costs	**-**	14	**-**	(242)
Acquisition of petroleum and natural gas properties	**(130)**	(2)	**(217)**	(387)
Change in non-cash working capital	**17,517**	27,726	**8,827**	19,492
	(8,267)	(16,060)	**(60,547)**	(67,404)
Increase (decrease) in cash and cash equivalents	**3,991**	(5,731)	**5,842**	24
Cash and cash equivalents, beginning of period	**5,890**	5,616	**4,039**	(139)
Cash and cash equivalents, end of period	**9,881**	(115)	**9,881**	(115)
Cash interest paid	**1,127**	1,133	**3,424**	3,838

See accompanying notes to the interim consolidated financial statements.

1) STRUCTURE OF DELPHI

Delphi Energy Corp. ("Delphi" or "the Company") is a publicly-traded company with its corporate office in Calgary, Alberta, Canada. Delphi is engaged in the exploration for, development and production of crude oil and natural gas from properties and assets located in Western Canada in which it holds an interest. The Company's operations are primarily concentrated in the Deep Basin of North West Alberta, representing in excess of 90 percent of the Company's production.

The interim consolidated financial statements as at and for the three and nine months ended September 30, 2011 comprise the accounts of the Company, its wholly-owned subsidiary and a partnership.

The audited consolidated financial statements of the Company as at and for the year ended December 31, 2010, which were prepared under previous Canadian Generally Accepted Accounting Principles (GAAP) are available through the Company's filings on SEDAR at www.sedar.com or can be obtained from Delphi's website at www.delphienergy.ca.

2) BASIS OF PRESENTATION

(a) Statement of compliance

These interim consolidated financial statements have been prepared in accordance with International Accounting Standards (IAS) 34 *Interim Financial Reporting*. These are the Company's third International Financial Reporting Standards (IFRS) interim consolidated financial statements for part of the period covered by the first IFRS annual financial statements and IFRS 1 *First-time Adoption of International Financial Reporting Standards* has been applied. The interim consolidated financial statements do not include all of the information required for full annual financial statements.

An explanation of how the transition to IFRS has affected the reported consolidated financial performance of the Company for the three and nine months ended September 30, 2010 is provided in note 7. This note includes reconciliations of total comprehensive earnings and shareholders' equity for the comparative periods reported under previous Canadian GAAP to those reported under IFRS.

These interim consolidated financial statements were approved by the Board of Directors on November 8, 2011.

(b) Basis of measurement

The interim consolidated financial statements have been prepared on the historical cost basis except for derivative financial instruments which are measured at fair value.

(c) Functional and presentation currency

These interim consolidated financial statements are presented in Canadian dollars, which is the Company's functional currency.

(d) Use of estimates and judgments

The preparation of the interim consolidated financial statements in conformity with IFRS requires management to make judgments, estimates and assumptions that affect the application of accounting policies and the reported amounts of assets, liabilities, shareholders' equity, revenue and expenses. Actual results may differ from these estimates.

Estimates and their underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognized in the period in which the estimates are revised and in any future periods affected.

In preparing these interim consolidated financial statements, the significant judgments made by management in applying the Company's accounting policies and the key sources of estimation uncertainty are expected to be the same as those to be applied in the first annual IFRS financial statements. These judgments, estimates and assumptions that have the most significant effect on the amounts recognized in the consolidated financial statements include the following:

vi) valuation of financial instruments;
vii) valuation of exploration and evaluation assets;
viii) valuation of property, plant and equipment;
ix) measurement of decommissioning obligations; and
x) measurement of share-based compensation.

Estimates of proved plus probable reserves have an effect on a number of the areas referred to above, in particular, the valuation of property, plant and equipment and the calculation of depletion and depreciation expense.

3) SIGNIFICANT ACCOUNTING POLICIES

The unaudited interim consolidated financial statements of Delphi have been prepared by management in accordance with International Financial Reporting Standards and following the same accounting policies and methods of computation as the unaudited interim consolidated financial statements for the three months ended March 31, 2011. The unaudited interim consolidated financial statements should be read in conjunction with the audited consolidated financial statements and notes thereto in the Company's Annual Report for the year ended December 31, 2010 and the unaudited interim consolidated financial statements and notes thereto in the Company's First Quarter Report for the three months ended March 31, 2011.

The Company's accounting policies have been applied consistently to all periods presented in these interim consolidated financial statements and have been applied consistently by the Company and its subsidiaries. Certain comparative amounts have been reclassified to conform to the current year's presentation.

(a) **Restricted Share Unit Plan**

In May, 2011 the Company, established a restricted share unit ("RSU") plan whereby the fair value of the RSU's is expensed into the statement of earnings over the same period that the units vest and at each reporting date between the grant date and settlement, the fair value of the liability is re-measured with any changes in fair value recognized in the statement of earnings for the period.

4) EXPLORATION AND EVALUATION ASSETS (E&E)

	Total
Balance as at January 1, 2010	315
Additions	2,472
Balance as at December 31, 2010	2,787
Additions	2,638
Balance as at September 30, 2011	**5,425**

5) PROPERTY, PLANT AND EQUIPMENT

Cost	**Crude oil and natural gas properties**	**Production equipment**	**Other assets**	**Total**
Balance as at January 1, 2010	198,595	133,771	572	332,938
Additions	81,991	20,928	49	102,968
Acquisitions	18	-	-	18
Dispositions	(247)	-	-	(247)
Change in decommissioning obligations	1,559	-	-	1,559
Balance as at December 31, 2010	281,916	154,699	621	437,236
Additions	59,964	15,169	51	75,184
Acquisitions	217	-	-	217
Dispositions	(8,443)	-	-	(8,443)
Change in decommissioning obligations	2,254	-	-	2,254
Balance as at September 30, 2011	**335,908**	**169,868**	**672**	**506,448**

Accumulated depletion and depreciation	Crude oil and natural gas properties	Production equipment	Other assets	Total
Balance as at January 1, 2010	-	-	-	-
Depletion and depreciation	(36,994)	(7,155)	(129)	(44,278)
Impairment losses	(30,500)	(5,000)	-	(35,500)
Balance as at December 31, 2010	(67,494)	(12,155)	(129)	(79,778)
Depletion and depreciation	(26,090)	(7,530)	(88)	(33,708)
Balance as at September 30, 2011	**(95,584)**	**(19,685)**	**(217)**	**(113,486)**
Net book value as at September 30, 2011	**242,324**	**150,183**	**455**	**392,962**
Net book value as at December 31, 2010	214,422	142,544	492	357,458

As at September 30, 2011, costs in the amount of $nil (September 30, 2010 - $6.1 million) representing work in progress were excluded from the depletion calculation and estimated future development costs of $134.9 million (September 30, 2010 - $48.4) have been included in costs subject to depletion.

During 2010, as a result of decreasing natural gas prices, the Company recognized an impairment of $35.5 million relating to several cash generating units ("CGU's") outside of the Company's focus area in the Deep Basin which predominantly produce natural gas only. The impairments were based on the difference between the period end net book value of the CGU's and the recoverable amount. The recoverable amount was determined using fair value less cost to sell based on discounted cash flows of proved plus probable reserves using discount rates of 12 to 15 percent.

6) SHARE CAPITAL

At September 30, 2011, the Company was authorized to issue an unlimited number of common shares. The holders of common shares are entitled to receive dividends as declared by the Company and are also entitled to one vote per share.

(a) Issued and outstanding

	September 30, 2011		December 31, 2010	
	Outstanding shares (000's)	**Amount**	Outstanding shares (000's)	Amount
Balance, beginning of period	**112,825**	**236,382**	101,166	206,382
Issue of common shares	**-**	**-**	11,000	30,250
Issue of flow-through common shares	**3,200**	**8,160**	-	-
Exercise of stock options	**1,910**	**2,424**	659	775
Allocated from contributed surplus	**-**	**1,269**	-	418
Share issue costs	**-**	**(32)**	-	(1,966)
Tax effect of share issue costs	**-**	**-**	-	523
Balance, end of period	**117,935**	**248,203**	112,825	236,382

On March 24, 2011, the Company issued 3.2 million flow-through common shares at a price of $2.80 per share for gross proceeds of $8.96 million. A flow-through premium of $0.8 million related to the issuance of the shares had been recorded as a long term liability on the consolidated statement of financial position on the date of issue. During the period, $5.8 million of qualifying expenditures were incurred resulting in a reduction in deferred income tax expense and a reduction of the long term liability of $0.5 million. The Company has an obligation to incur qualifying exploration expenditures by December 31, 2012 to satisfy the terms of the flow-through common shares issued.

(b) Share-based compensation

The Company has established a stock option plan under which it has granted options to acquire common shares to certain officers, directors, employees and key consultants. The plan provides for the granting of options up to ten percent of the issued and outstanding common shares of the Company. Options issued under the plan have a term of five years to expiry. Options granted prior to September 1, 2009 vest over a two-year period starting on the date of grant. Options granted between September 1, 2009 and May 31, 2011 vest over a two-year period with one-third vesting six months after the date of grant and one-third on each of the first and second anniversary of the grant date. Options granted on May 31, 2011 or later vest over a four-year period with one-fourth vesting on each of the first, second, third and fourth anniversary of the grant date. The exercise price of each option equals the five day weighted average of the market price of the Company's common shares, immediately preceding the date of the grant. As at September 30, 2011 there were 8.8 million options to purchase shares outstanding.

The following table summarizes the changes in the number of options outstanding and the weighted average exercise prices.

	September 30, 2011		December 31, 2010	
	Outstanding options (000's)	**Weighted average exercise price**	Outstanding options (000's)	Weighted average exercise price
Balance, beginning of period	**7,776**	**1.59**	7,428	1.40
Granted	**3,680**	**2.53**	1,074	2.64
Forfeited	**(768)**	**2.45**	(67)	1.50
Exercised	**(1,909)**	**1.27**	(659)	1.18
Balance, end of period	**8,779**	**1.98**	7,776	1.59
Exercisable, end of period	**5,294**	**1.62**	6,116	1.58

The following table summarizes information about the stock options outstanding and exercisable at September 30, 2011.

	Options outstanding			Options exercisable	
Range of exercise price	Outstanding options (000's)	Weighted average exercise price	Weighted average remaining term (years)	Exercisable (000's)	Weighted average exercise price
$0.65 - $0.97	**1,099**	**0.65**	**2.42**	**1,099**	**0.65**
$0.98 - $1.54	**265**	**1.21**	**2.58**	**265**	**1.21**
$1.55 - $1.72	**2,760**	**1.68**	**1.20**	**2,735**	**1.68**
$1.73 - $2.15	**605**	**1.90**	**2.10**	**465**	**1.83**
$2.16 - $3.34	**4,050**	**2.61**	**4.30**	**730**	**2.86**
Total	**8,779**	**1.98**	**2.89**	**5,294**	**1.62**

The weighted average share price at the date of exercise for stock options exercised in 2011 was $ 2.33 (2010 - $2.66.

The Company accounts for its share-based compensation using the fair value method for all stock options. For the nine months ended September 30, 2011, Delphi recorded non-cash compensation expense of $0.6 million (September 30, 2010 - $0.8 million).

During the nine months ended September 30, 2011, the Company granted 3.7 million options. The fair values of all options granted during the period are estimated at the date of grant using the Black-Scholes option pricing model. The weighted average fair value of options granted during the period was $2.53 per option (September 30, 2010 - $1.55 per option). The assumptions used in the Black-Scholes model to determine fair value were as follows.

For the nine months ended September 30	**2011**	2010
Risk-free interest rate (%)	**2.1**	2.8
Expected life (years)	**4.2**	5.0
Forfeiture rate (%)	**14.1**	3.6
Expected volatility (%)	**66.5**	65.9

During the nine months ended September 30, 2011, the Company established a restricted share unit ("RSU") plan. Employees are eligible to receive RSU awards or convert up to 50 percent of their performance bonus into RSU awards. RSU awards received by an employee as a result of conversion, receive a 30 percent increase in the number of RSU's received through the conversion. The RSU awards vest on each of the first, second and third anniversary of the award date at which time the employee will receive a cash payment equivalent to the number of RSU's vested multiplied by the Company's closing share price on the business day immediately preceding the vesting date.

		September 30, 2011
	Outstanding RSU's	Amount
Restricted share unit obligation	**58,012**	**11**

(c) Net earnings per share

Net earnings per share has been calculated based on the following weighted average common shares.

	Three Month Ended September 30		**Nine Months Ended September 30**	
	2011	2010	**2011**	2010
Weighted average common shares - basic	**117,660**	112,698	**116,204**	106,293
Stock options	**1,576**	-	**2,051**	-
Weighted average common shares - diluted	**119,236**	112,698	**118,255**	106,293

For the three and nine months ended September 30, 2010, the stock options were anti-dilutive and therefore excluded from the calculation of weighted average common shares.

7) FIRST TIME ADOPTION OF INTERNATIONAL FINANCIAL REPORTING STANDARDS

These are the Company's third interim consolidated financial statements for the period covered by the first annual consolidated financial statements to be prepared in accordance with IFRS.

The accounting policies outlined in Note 3 have been applied in preparing the interim consolidated financial statements for the three and nine months ended September 30, 2011 and the comparative information for the three and nine months ended September 30, 2010.

An explanation of how the transition from previous Canadian GAAP to IFRS has affected the Company's financial performance for the three and nine months ended September 30, 2010 is set out in the following tables.

Key First Time Adoption Exemptions Applied

IFRS 1 *First Time Adoption of International Financial Reporting Standards* allows first time adopters certain exemptions from retrospective application of certain IFRS.

The Company has applied the following exemptions:

- Previously, crude oil and natural gas assets in property, plant and equipment on the statement of financial position were recognized and measured on a full cost basis in accordance with previous Canadian GAAP. The Company has elected to measure its properties at the amount determined under previous Canadian GAAP as at January 1, 2010. Costs included in the full cost pool on January 1, 2010 were allocated on a pro-rata basis to the underlying assets on the basis of total proved plus probable reserve values as at January 1, 2010. Decommissioning liabilities were measured using a risk free rate, with a corresponding adjustment recorded to opening retained earnings.

- IFRS 3 *Business Combinations* has not been applied to acquisitions of subsidiaries or interests in joint ventures that occurred before January 1, 2010.

IFRS Consolidated Statement of Earnings (Loss) and Comprehensive Earnings (Loss)
For the three months ended September 30, 2010

(thousands of dollars)	Notes	Previous GAAP	Effect of Transition to IFRS	IFRS
Revenue				
Petroleum and natural gas sales		26,554	-	26,554
Royalties		(2,993)	-	(2,993)
		23,561	-	23,561
Realized gain on financial instruments		1,526	-	1,526
Unrealized loss on financial instruments		(956)	-	(956)
		24,131	-	24,131
Expenses				
Operating	**d)**	5,561	(9)	5,552
Transportation		2,149	-	2,149
Exploration and evaluation	**a)**	-	(14)	(14)
General and administrative	**d)**	1,154	141	1,295
Share-based compensation	**c)**	370	14	384
Depletion and depreciation	**b)**	15,594	25,485	41,079
		24,828	25,617	50,445
Finance costs	**e)**	1,325	(104)	1,221
Loss before taxes		(2,022)	(25,513)	(27,535)
Taxes				
Deferred income taxes (reduction)	**f)**	(456)	(6,607)	(7,063)
Net Loss and comprehensive loss		(1,566)	(18,906)	(20,472)

IFRS Consolidated Statement of Earnings (Loss) and Comprehensive Earnings (Loss)
For the nine months ended September 30, 2010

(thousands of dollars)	Notes	Previous GAAP	Effect of Transition to IFRS	IFRS
Revenue				
Petroleum and natural gas sales		83,980	-	83,980
Royalties		(11,526)	-	(11,526)
		72,454	-	72,454
Realized gain on financial instruments		2,744	-	2,744
Unrealized gain on financial instruments		1,282	-	1,282
		76,480	-	76,480
Expenses				
Operating	**d)**	17,397	(50)	17,347
Transportation		6,819	-	6,819
Exploration and evaluation	**a)**	-	242	242
General and administrative	**d)**	3,943	771	4,714
Share-based compensation	**c)**	795	33	828
Depletion and depreciation	**b)**	44,084	22,504	66,588
		73,038	23,500	96,538
Finance costs	**e)**	4,497	(338)	4,159
Loss before taxes		(1,055)	(23,162)	(24,217)
Taxes				
Deferred income taxes (reduction)	**f)**	(7)	(5,482)	(5,489)
Net loss and comprehensive loss		(1,048)	(17,680)	(18,728)

IFRS Changes in Shareholders' Equity
As at September 30, 2010

(thousands of dollars)	Notes	Previous GAAP	Effect of Transition to IFRS	IFRS
Shareholders' equity				
Share capital	**g)**	228,281	7,942	236,223
Contributed surplus	**h)**	11,820	5	11,825
Deficit	**i)**	(741)	(32,412)	(33,153)
Total shareholders' equity		239,360	(24,465)	214,895

Notes to reconciliations:

a) Property, plant and equipment (PP&E) – Delphi's PP&E assets were allocated to CGU's whereas under previous Canadian GAAP all crude oil and natural gas assets were accumulated into one cost centre. The deemed cost of Delphi's crude oil and natural gas assets were allocated to its defined CGU's based on Delphi's total proved plus probable reserve values as at January 1, 2010, in accordance with IFRS 1. These CGU's were aligned within the major geographic regions in which Delphi operates and could change in the future as a result of acquisition and disposition activity. The following tables highlight the changes in property, plant and equipment and the effect on the consolidated statement of earnings as a result of the transition from previous GAAP to IFRS.

Consolidated statement of earnings	**Three Months Ended September 30, 2010**	**Nine Months Ended September 30, 2010**
Expensing of dry hole costs	(14)	242

b) Depletion and depreciation expense – Delphi has chosen to calculate its depletion using a reserve base of total proved plus probable reserves, as compared to using only proved reserves under previous Canadian GAAP. As a result, the depletion and depreciation expense decreased as compared to its calculation under previous Canadian GAAP.

Consolidated statement of earnings	**Three Months Ended September 30, 2010**	**Nine Months Ended September 30, 2010**
Decrease in depletion and depreciation	(5,015)	(12,996)
Impairment losses	30,500	35,500
Increase in depletion and depreciation	25,485	22,504

Impairment of PP&E assets – Under IFRS, an impairment test of PP&E is performed at the CGU level as opposed to the entire PP&E balance, which was required under previous GAAP through the full cost ceiling test. Delphi is required to recognize an impairment loss if the carrying amount of a CGU exceeds the higher of its fair value less cost to sell and value in use. Under previous GAAP, estimated future cash flows used to assess whether an impairment has occurred were not discounted.

During the first nine months of 2010, as a result of decreasing natural gas prices, the Company recognized a $35.5 million impairment relating to several CGU's outside the Company's focus area in the Deep Basin which predominantly produced natural gas.

c) Share-based compensation – Delphi is required to utilize a forfeiture rate in its calculation of share-based compensation, unlike under previous Canadian GAAP where this was an option but not required.

Consolidated statement of earnings	**Three Months Ended September 30, 2010**	**Nine Months Ended September 30, 2010**
Change to share-based compensation	(33)	(54)
Share-based compensation capitalized to PP&E	54	143
Share-based compensation capitalized to E&E	(7)	(56)
	14	33

d) Capitalized directly related overhead

Consolidated statement of earnings	Three Months Ended September 30, 2010	Nine Months Ended September 30, 2010
Decrease in capitalized directly related overhead	132	721
Transfer from operating expense to general and administration	9	50
	141	771

e) Finance costs – Accretion expense is classified as a finance cost rather than depletion and depreciation and includes the impact of using a risk-free rate.

Consolidated statement of earnings	Three Months Ended September 30, 2010	Nine Months Ended September 30, 2010
Accretion expense	(104)	(338)

f) Deferred income tax – Delphi recorded a decrease of $2.7 million to its deferred tax liability upon transition to IFRS with the offset to opening retained earnings. The change in deferred tax liability is primarily due to the adjustments to the balances of property, plant and equipment and decommissioning liabilities on transition to IFRS.

Consolidated statement of earnings	Three Months Ended September 30, 2010	Nine Months Ended September 30, 2010
Deferred income tax related to transition to IFRS	(6,607)	(5,482)

g) Share Capital - Delphi recorded an increase of $7.4 million to its share capital upon transition to IFRS, with the offset to opening retained earnings, relating to the recording of flow-through shares under IFRS. Under previous GAAP, the tax renouncement related to flow-through shares was recorded against share capital whereas under IFRS only the portion related to the flow-through premium is recorded against share capital. This change is retrospective for all flow-through share issuances. For the flow-through share issuance in 2009, where the qualifying expenditures were incurred in 2010, the flow-through premium of $1.0 million is recorded in other liabilities instead of share capital until the qualifying expenditures are incurred, at which point the flow-through premium is recorded in deferred income taxes on the statement of earnings.

Delphi recorded a decrease of $0.1 million to its share capital upon transition to IFRS, with the offset to opening retained earnings, relating to changes in the treatment of the tax effect of share issue costs under IFRS.

Consolidated statement of financial position

	September 30, 2010
Flow-through adjustment	7,409
Flow-through issuance in 2009	655
Share issue cost adjustment	(122)
	7,942

h) Contributed Surplus - Delphi is required to utilize a forfeiture rate in its calculation of share-based compensation, unlike under previous GAAP where this was an option but not required.

Consolidated statement of financial position

	September 30, 2010
Change due to forfeiture rate	5

i) Deficit - Under IFRS, Delphi remeasured its liability for asset retirement obligations using the risk-free rate of interest. IFRS requires that decommissioning obligations be remeasured each reporting period for changes in the discount rate with a corresponding adjustment to the cost of property, plant and equipment. At January 1, 2010 Delphi's total decommissioning liabilities increased by $6.2 million to $18.1 million as the liability was revalued to reflect the estimated risk-free rate of interest of 3.6% as compared to the credit adjusted risk-free rate of 8 – 10% used under previous GAAP.

Upon transition to IFRS, Delphi recorded an impairment on its East Central Alberta cash generating unit to a net realizable value of $0.3 million, with the impairment of $3.9 million recognized in opening retained earnings as required by IFRS 5. The remaining carrying value was reclassified to assets and liabilities held for sale. The net assets were sold in the second quarter of 2010 for $0.3 million.

Consolidated statement of financial position

		September 30, 2010
Decommissioning obligations	i)	(6,124)
Share-based compensation	c)	(12)
Flow-through adjustment	g)	(8,064)
Impairment of assets held for sale	i)	(3,895)
Share issue cost adjustment	g)	122
Deferred income tax	f)	8,799
Capitalized directly related overhead	d)	(721)
Depletion and depreciation	b)	12,996
Rate change in decommissioning obligations	i)	229
Expensing of dry hole costs	a)	(242)
Impairment loss	b)	(35,500)
		(32,412)

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INDEPENDENT ENGINEERS

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STOCK EXCHANGE LISTING

Toronto Stock Exchange – DEE

TRANSFER AGENT

Olympia Trust Company

ABBREVIATIONS

bbls....barrels
bbls/d ....barrels per day
mbbls....thousand barrels
mcf ....thousand cubic feet
mcf/d ....thousand cubic feet per day
mmcf ....million cubic feet
mmcf/d ....million cubic feet per day
NGL ....natural gas liquids
bcf ....billion cubic feet
boe ....barrels of oil equivalent (6 mcf:1 bbl)
boe/d ....barrels of oil equivalent per day
mmboe ....million barrels of oil equivalent

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