This is Delphi.

DELPHI ENERGY CORP. | FOR THE THREE MONTHS ENDED MARCH 31, 2011

300, 500 – 4 Avenue SW, Calgary, Alberta T2P 2V6 | t: (403) 265-6171 | f: (403) 265-6207 | e: info@delphienergy.ca | www.delphienergy.ca | TSX Symbol: DEE

Q1

First Quarter 2011 Highlights

- increased crude oil and natural gas liquids ("NGL's") production by 74 percent to 2,174 barrels per day, achieving average corporate production of 8,259 barrels of oil equivalent per day ("boe/d"), an increase of 8 percent compared to the first quarter of 2010;
- changed the production mix to approximately 26 percent crude oil and natural gas liquids in the first quarter of 2011, up from 16 percent in the first quarter of 2010;
- reduced operating costs by 22 percent to $6.77 per boe in the first quarter of 2011 from $8.70 per boe in the comparative quarter of 2010;
- generated funds from operations ("cash flow") of $15.1 million, an increase of 2 percent from the comparative quarter of 2010;
- achieved a cash netback of $20.26 per boe, achieving the Company's objective of maintaining a cash netback of at least $20.00 per boe in this low natural gas price environment;
- realized $2.1 million in hedging gains on natural gas contracts, achieving a 22 percent premium to AECO pricing of $3.80 per mcf, while incurring $0.2 million of hedging losses on a crude oil call option;
- drilled 13 (10.4 net) wells with an overall success rate of 100 percent;
- issued 3.2 million flow-through common shares for net proceeds of $9.0 million; and
- increased the Company's credit facilities from $140.0 million to $145.0 million based upon the Company's reserves growth in the December 31, 2010 year end engineering report and the successful first quarter of 2011 capital program.

Financial Highlights ($ thousands except per unit amounts)

	Three Months Ended March 31		
	2011	2010	% Change
Petroleum and natural gas sales	**29,163**	29,519	(1)
Per boe	**39.23**	42.90	(9)
Funds from operations	**15,061**	14,751	2
Per boe	**20.26**	21.44	(5)
Per share – Basic	**0.13**	0.15	(13)
Per share – Diluted	**0.13**	0.15	(13)
Net earnings	**962**	1,613	(40)
Per boe	**1.29**	2.34	(45)
Per share – Basic	**0.01**	0.02	(50)
Per share – Diluted	**0.01**	0.02	(50)
Capital invested	**34,297**	35,098	(2)
Disposition of properties	**(273)**	-	100
Net capital invested	**34,024**	35,098	(3)
Acquisition of properties	**87**	692	(87)
Total capital invested	**34,111**	35,790	(5)

	March 31, 2011	December 31, 2010	% Change
Debt plus working capital deficiency (1)	**116,879**	108,054	8
Total assets	**416,679**	387,687	7
Shares outstanding (000's)			
Basic	**117,121**	112,825	4
Diluted	**123,796**	120,601	3

(1) excludes the fair value of financial instruments.

Operational Highlights

	Three Months Ended March 31		
Production	**2011**	2010	% Change
Natural gas (mcf/d)	**36,509**	38,349	(5)
Crude oil (bbl/d)	**1,102**	745	48
Natural gas liquids (bbl/d)	**1,072**	508	111
Total (boe/d)	**8,259**	7,645	8

MESSAGE TO SHAREHOLDERS

Production during the first quarter of 2011 averaged 8,259 boe/d, an increase of 8 percent compared to 7,645 boe/d in the first quarter of 2010. The increased light oil production at Hythe and Bigstone changed the production mix in the quarter to 26 percent liquids (74 percent natural gas) from 16 percent liquids (84 percent natural gas) in the first quarter of 2010. The change in production mix to higher netback oil and NGLs contributed to first quarter cash flow. Production for the second quarter of 2011 is forecast to be 9,000 to 9,200 boe/d.

Cash flow in the first quarter of 2011 was $15.1 million or $0.13 per basic share, compared to $14.8 million or $0.15 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 prices offset by the decrease in realized natural gas prices.

Operating costs before processing income were $0.9 million lower than the comparative quarter despite average production growth of eight percent over the same time. The fixed costs associated with owned natural gas plant infrastructure, field compression facilities and pipelines continue to be allocated over more production volumes resulting in lower marginal costs of new production. 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 lower by $1.93 to $6.77 per boe in the first quarter of 2011, 22 percent lower than the comparative period.

For the quarter ended March 31, 2011, the Company recognized approximately $1.9 million in realized gains on financial and physical hedging contracts providing significant 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 first quarter of 2011, providing the financial flexibility to execute the second half of the 2011 capital program. At March 31, 2011, the Company had net debt of $116.9 million on total credit facilities of $145.0 million, providing excess financial capacity of approximately $28.1 million. On an annualized, first quarter funds from operations basis, Delphi's net debt to cash flow ratio was 1.9:1. Net debt includes bank debt plus working capital deficiency excluding the fair value of financial instruments.

Operations

During the first quarter, the Company drilled 13 wells (10.4 net) within its core areas of Wapiti, Bigstone and Hythe. Five horizontal wells (3.15 net) were targeting light oil in the Doe Creek formation at Hythe and the Cardium formation at Bigstone. At Wapiti, seven vertical wells (6.21 net) targeted liquids-rich natural gas in the Nikanassin and uphole Cretaceous intervals and at Hythe one vertical well (1.00 net) was drilled targeting natural gas in the Cretaceous interval. Nine wells (6.52 net) have been completed and brought on-stream and four wells (3.84 net) will be brought on-stream early in the third quarter. Based on production results and data acquired during drilling operations the Company anticipates a success rate of 100 percent.

Better than expected results at Wapiti required gathering system modifications which are nearing completion and will position the Company to have a takeaway capacity of approximately 7,000 boe/d ensuring capacity for future development programs. At Hythe the Company has completed a preliminary evaluation of its Hythe area gas processing facility to increase liquids recovery from approximately 8 barrels per million to in excess of 20 barrels per million. Through the second half of 2011 the Company will continue to move this project forward by obtaining partner and regulatory approvals, performing detailed engineering and sourcing the necessary equipment with implementation planned for the first half of 2012.

Wapiti

Nikanassin Liquids-Rich Natural Gas Program

During the first quarter, the Company drilled seven vertical wells (6.21 net) targeting liquids-rich natural gas in the Nikanassin and shallower Cretaceous intervals. Four of the these wells (3.37 net) have been completed and brought on-line with individual 30 day average production rates ranging from 1,475 to 3,100 mcf per day resulting in an 30 day average per well rate of 2,280 mcf per day (470 boe/d). The remaining three wells (2.84 net), drilled in the first quarter, will be completed and brought on-stream after break-up. An additional two wells (1.84 net), drilled in the fourth quarter of 2010, were brought on-stream during the first quarter with 30 day average production rates of 1,230 mcf per day (220 boe/d) and 3,800 mcf per day (905 boe/d). Producing intervals in the Wapiti area have a liquids content of up to 120 barrels per million cubic feet of gas resulting in a production stream that is expected to be 45 percent, high netback natural gas liquids.

At Wapiti, the Company plans to drill eight wells (6.2 net) for the remainder of 2011 and is in various stages of licensing an additional ten wells for follow-up drilling in the 2011/2012 winter program. The Company has been adding to its Wapiti land base and currently has an average working interest of 57 percent in 107 sections of land with regulatory approval to drill up to four wells per section

Infrastructure

In order to increase the takeaway capacity for planned future volumes, the Company's has initiated several de-bottlenecking projects associated with the field gathering system to almost triple takeaway capacity from 2,500 boe/d to approximately 7,000 boe/d (45 percent NGL's). The infrastructure projects are nearing completion and will be fully operational during the third quarter

Bigstone

Cardium Light Oil Program

The Company drilled, completed and brought on-stream three horizontal wells (1.15 net) targeting light oil in the Cardium interval during the first quarter. An additional two wells (0.10 net), drilled during the fourth quarter of 2010, were also completed and brought on-stream during the first quarter. The 30 day average production rates per well is 173 boe/d with individual 30 day average rates as high as 387 boe/d.

The Company will initiate the 2011/2010 winter drilling program with plans to drill two horizontal wells (1.0 net) during the fourth quarter of 2011. Currently, Delphi controls 17 net sections of Cardium rights with ultimate development potential of two to four wells per section

Hythe

Doe Creek Light Oil Program

The Company drilled, completed and brought on-stream two horizontal wells (2.00 net) targeting light oil in the Doe Creek interval during the first quarter. One additional horizontal well (0.40 net), drilled during the fourth quarter of 2010, was also completed and brought on-stream during the first quarter. The three wells had individual 30 day average production rates ranging from 94 to 328 boe/d resulting in a 30 day average per well rate of 226 boe/d.

At Hythe the Company is currently developing two separate Doe Creek pools with horizontal wells and multistage fracture completions. To initiate the second half drilling program, Delphi will be mobilizing a rig to spud a horizontal Doe Creek well (1.0 net) in early June. In preparation for the 2011/2012 winter capital program, Delphi and its partners continue to license additional wells.

Cretaceous Natural Gas Program

The Company drilled one vertical well (1.00 net) targeting natural gas in the Cretaceous section during the first quarter. Two intervals were completed and tested at a rate of 850 mcf/d (140 boe/d). Equipping and tie-in operations are planned for the second quarter.

Infrastructure

In order to add value to the existing reserve base and enhance economics associated with development of future natural gas projects, the Company has been evaluating an upgrade to the NGL recovery process at its Hythe area gas processing facility. The intent is to increase the amount of liquids recovered from the natural gas stream from approximately 8 bbls per million to in excess of 20 bbls per million. A capital expenditure of five to seven million dollars would be required for the required upgrades pending partner and regulatory approval. The increased liquids yield and enhance drill well economics would be instrumental in developing Delphi's high working interest land base of 283 sections in the Hythe area.

Outlook

The Company expects to spend an estimated $80.0 million in 2011, with field capital directed towards drilling opportunities in the Bigstone, Hythe and Wapiti/Gold Creek core areas. The planned capital program, funded from cash flow and the recent equity offering. Guidance for 2011 production volumes remains unchanged at 8,800 to 9,200 boe/d.

Delphi is now assuming 2011 AECO natural gas prices will 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 again hedged with approximately 60 percent of its natural gas production protected at an average floor price of $4.81 per mcf. This represents a 27 percent premium to the 2011 strip price of $3.78 per mcf. The growth in liquids production, 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, up from previous guidance of $63.0 to $65.0 million.

Bank debt including working capital is estimated to be between $110.0 million and $115.0 million at December 31, 2011 resulting in a debt to cash flow ratio of approximately 1.6:1.

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
May 25, 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 months ended March 31, 2011 and 2010 and should be read in conjunction with Note 15 of the unaudited consolidated interim financial statements and accompanying notes for the three months ended March 31, 2011 and the audited consolidated financial statements and accompanying notes for the years ended December 31, 2010 and 2009. The interim consolidated financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS") including International Accounting Standard 34 "Interim Financial Reporting". Previously the Company prepared its interim and annual consolidated financial statements in accordance with Canadian generally accepted accounting principles. The reporting currency is the Canadian dollar. The discussion and analysis has been prepared as of May 25, 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, deferred income taxes and unrealized gain/(loss) on financial instruments) and excludes the change in non-cash working capital related to operating activities and expenditures on decommissioning obligations. 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 deferred income taxes and 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.

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, Wapiti/Gold Creek.

FIRST QUARTER 2011 ACCOMPLISHMENTS

What were the highlights of Delphi's operations in the first quarter of 2011?

Canadian natural gas prices continued to be challenging in the early part of 2011, decreasing 23 percent from the same quarter of 2010. At the same time, Canadian light oil prices increased ten percent from the same quarter of 2010. Delphi focused its exploitation efforts in its core areas in the Deep Basin of North West Alberta, in particular on its Wapiti/Gold Creek property, with vertical and horizontal drilling operations emphasizing light oil and liquids-rich natural gas opportunities. Hence, despite a significant decrease in natural gas prices, the Company enjoyed another successful quarter towards continued growth in long-term value for its shareholders.

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

- achieved average production of 8,259 barrels of oil equivalent per day ("boe/d"), an increase of eight percent compared to the first quarter of 2010;
- changed the production mix to approximately 26 percent crude oil and natural gas liquids in the first quarter of 2011, up from 16 percent in the first quarter of 2010;
- generated funds from operations ("cash flow") of $15.1 million, an increase of two percent from the comparative quarter of 2010;
- achieved a cash netback of $20.26 per boe, achieving the Company's objective of maintaining a cash netback of at least $20.00 per boe in this low natural gas price environment;
- reduced operating costs by 22 percent to $6.77 per boe in the first quarter of 2011 from $8.70 per boe in the comparative quarter of 2010;
- realized $2.1 million in hedging gains on natural gas contracts while incurring $0.2 million of hedging losses on a crude oil call option;

- drilled 13 (10.4 net) wells with an overall success rate of 100 percent;
- issued 3.2 million flow-through common shares for net proceeds of $9.0 million; and
- increased the Company's credit facilities from $140.0 million to $145.0 million based upon the Company's reserves growth in the December 31, 2010 year end engineering report and the successful first quarter of 2011 capital program.

Cash flow in the first quarter of 2011 was $15.1 million or $0.13 per basic share, compared to $14.8 million or $0.15 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 prices offset by the decrease in realized natural gas prices.

Operating costs before processing income were $0.9 million lower than the comparative quarter despite average production growth of eight percent over the same time. The fixed costs associated with owned natural gas plant infrastructure, field compression facilities and pipelines continue to be allocated over more production volumes resulting in lower marginal costs of new production. 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 lower by $1.93 to $6.77 per boe in the first quarter of 2011, 22 percent lower than the comparative period.

For the quarter ended March 31, 2011, the Company recognized approximately $1.9 million in realized gains on financial and physical hedging contracts providing significant stability to the Company's cash flow.

On March 24, 2011, the Company closed an equity offering of 3.2 million flow-through common shares at $2.80 per share for net proceeds of approximately $9.0 million. The proceeds were initially used to reduce the Company's net debt and will subsequently be used to fund the Company's capital program in the second half of 2011.

The combination of the above highlighted items resulted in Delphi's financial position continuing to remain strong at the end of the first quarter of 2011, providing the financial flexibility to execute the second half of the 2011 capital program. At March 31, 2011, the Company had net debt of $116.9 million on total credit facilities of $145.0 million, providing excess financial capacity of approximately $28.1 million. On an annualized, first quarter funds from operations basis, Delphi's net debt to cash flow ratio was 1.9:1. Net debt includes bank debt plus working capital deficiency excluding the fair value of financial instruments.

FINANCIAL STRATEGIES

Are there financial strategies the Company employs to achieve results and forecast expectations?

The Company maintains an active risk management program as an integral part of its overall financial strategy to mitigate volatility in cash flow resulting from fluctuating commodity prices. Delphi's program involves executing numerous contracts over a period of time to take advantage of the volatility in the natural gas and light crude oil market. The strategy takes advantage of the swings in prices as a result of a) the changes in demand/supply fundamentals and/or b) the movement of significant financial assets invested in the market as a pure commodity play. The transactions are generally undertaken for contract terms 12 to 24 months in advance with financially strong counterparties and are predominantly executed on a physical basis with the Company's natural gas marketer. Delphi's risk management program consists of fixed price contracts, costless collars, participating swaps and puts and calls which provide downside protection. Costless collars, participating swaps and puts also provide the opportunity to share in the upside if market prices increase above the floor price. If market prices are above fixed price contracts or the ceiling price of costless collars and calls, the Company would continue to achieve its downside protection while realizing losses on these hedging contracts. Delphi has a strategy of hedging approximately 40 to 50 percent of its production as long as demand/supply fundamentals indicate volatile markets in the future.

Delphi continues to direct efforts at maintaining or reducing its controllable costs. Increasing production at its operating fields which are processed through Company owned infrastructure reduces facility fixed costs on a per boe basis and improves netbacks. Field operators are encouraged to undertake preventative maintenance on field infrastructure and wellsite equipment to minimize production downtime and prevent significant operating costs associated with major repairs. The Company strives to achieve improvement in its costs of production and at a minimum maintain current production costs while growing production.

Maintaining or improving strong operating netbacks per boe through the risk management program and the control of costs associated with production operations and corporate overhead, allows the Company to pursue its planned capital program with greater confidence that financial flexibility will be maintained while incurring capital expenditures to grow production volumes. The risk management program has been and will continue to be an integral part of maximizing operating netbacks during periods of price volatility and excess natural gas supply.

As a result of the significant difference in netbacks between crude oil and natural gas, the Company's capital expenditures have been allocated more towards light oil and liquids-rich natural gas opportunities. By altering the Company's production mix, there is greater certainty of achieving the Company's cash flow expectations due to the higher netback crude oil and natural gas liquids production.

The annual net capital expenditure program in the field will continue to approximate forecast cash flow. Additional capital may be approved as a result of opportunistic acquisitions, incremental cash flow from greater than expected production growth, higher than forecast cash netbacks or other sources of financing.

Delphi continues to be focused on reducing its leverage and improving its financial flexibility through net debt reduction or increasing cash flow growth resulting in a lower net debt to funds from operations ratio. The Company continues to be focused on achieving its internal target ratio of 1.5 times. In a low price environment, the Company's objective would be to reduce or at least not increase the net debt balance by undertaking a capital program within cash flow.

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 May 25, 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 23 gross wells (17.6 net) 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/Gold Creek, the drilling will primarily be directed at vertical multi-zone opportunities with the liquids-rich Nikanassin formation being the primary target. 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 9,200 boe/d in 2011, up eleven 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. These production and sales mix expectations may not be achieved if decline rates are greater than expected, the new wells do not perform as expected, drilling plans are delayed for the reasons outlined above, completion and tie-in of new wells is delayed due to weather or the unavailability of the required service equipment in the field, mechanical failure of field equipment, delays in accessing production facilities or additional waiting time for any approvals.

REVENUES

What does the Company project for crude oil and natural gas prices in 2011?

Natural Gas

United States natural gas prices are commonly referenced to the New York Mercantile Exchange Henry Hub in Louisiana (NYMEX) while Canadian natural gas prices are typically referenced to the Canadian Alberta Energy Company interconnect with the TransCanada Alberta system (AECO). Natural gas prices are primarily influenced by North American, rather than global, supplies of natural gas versus domestic demand for winter heating and cooling demand for the summer. However, with the growth in natural gas liquefaction and regasification facilities around the world this North American supply and demand balance is subject to disruption from time to time, primarily in periods of a shortfall in supply. In addition, multi-stage fracturing technology has unlocked the significant natural gas resource potential of numerous shale basins in North America capable of initially producing at very high rates of natural gas.

For forecasting purposes, Delphi continues to expect a challenging natural gas market for 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. In light of the low natural gas prices experienced in the first five months of 2011, the Company has reduced its 2011 expectations for AECO to an average price of $3.70 per mcf, down from $4.00 per mcf previously.

Crude Oil

West Texas Intermediate at Cushing, Oklahoma (WTI) is the benchmark reference for North American crude oil prices. Canadian crude oil prices are based upon postings, primarily at Edmonton, Alberta and represent the WTI price adjusted for quality and transportation differentials as well as the Canadian/United States (“Cdn/US”) dollar exchange rate. The fundamental supply/demand equation for crude oil is more balanced on a daily basis than natural gas due to consistent demand for crude oil of approximately 88 million barrels per day to meet the global requirement for energy. The price of crude oil can also be influenced significantly by geopolitical events in the major oil exporting countries of the world and the strength or weakness of the global economies.

Delphi has also revised its expectations for the price of crude oil. Previous guidance was based on an average WTI price of U.S. $85.00 per barrel in 2011. Incorporating the higher WTI prices realized in the first four months of 2011, Delphi now believes WTI will average U.S. $96.50 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 strength or weakness of the Canadian dollar versus the U.S. dollar will largely reflect the global demand for raw materials, particularly metals, minerals and crude oil. The global financial markets tolerance for risk and its need for financial security in the form of holding U.S dollars will also have an effect on the value of the Canadian dollar against the U.S. dollar. Delphi believes the Canadian dollar will remain quite strong relative to the U.S. dollar in 2011 as global economies continue to recover from the slowdown since 2008.

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 $0.96 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 more than an 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 60 percent of its before-royalty natural gas production at a predominantly AECO based average floor price of $4.81 per mcf for the remainder of 2011. This compares to the forward strip commodity price for AECO of $3.78 per mcf for the remainder of 2011 as of May 18, 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.

	Apr-Sep 2011	Oct-Dec 2011	2012
Production hedged (mmcf/d)	25.4	19.8	2.3
Percentage of natural gas production *	65%	51%	6%
Price floor (Cdn $/mcf)	$4.76	$4.88	$4.70

* based on 39 mmcf/d

The Company also has 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 $3.9 million with a loss of approximately $6.1 million on outstanding crude oil contracts as of May 18, 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 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 $2.75 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, all areas with an 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. Further reductions in operating costs are anticipated resulting in expected operating costs averaging between $6.50 and $6.75 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 costs to retain employees 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 $1.60 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 of approximately $80.0 million resulting in net debt levels between $110.0 and $115.0 million by the end of 2011. Growth in cash flow to approximately $67.0 million is expected to result in a net debt to cash flow ratio of approximately 1.6:1 at the end of 2011.

As in prior years, net debt is expected to decrease through the second quarter as capital expenditures are expected to be minimal due to spring breakup. The significant excess cash flow generated in the second quarter will be applied against net debt. Capital expenditures for the second half of the year will be planned according to the cash flow generated and achieving net debt targets.

BUSINESS ENVIRONMENT

What external factors of the business environment did the Company have to contend with in the first 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 March 31		
	2011	2010	% Change
Natural Gas			
NYMEX (US $/mmbtu)	**4.19**	5.14	(19)
AECO (CDN $/mcf)	**3.80**	4.96	(23)
Crude Oil			
West Texas Intermediate (US $/bbl)	**94.18**	78.79	20
Edmonton Light (CDN $/bbl)	**88.12**	80.07	10
Foreign Exchange			
Canadian to U.S. dollar	**0.99**	1.04	(5)
U.S. to Canadian dollar	**1.01**	0.96	6

Natural Gas

Natural gas prices were relatively strong due to cold weather in the early part of the first quarter with anticipation of normal withdrawals of natural gas from storage to meet winter heating demand. In February, however, natural gas prices began to decrease as natural gas drilling activity remained reasonably strong and the primary geographical areas for natural gas demand during the winter heating season began experiencing above average temperatures.

AECO gas prices hit a low of $3.19 per mcf in the quarter but recovered to $3.96 per mcf by the end of the quarter. AECO averaged $3.80 per mcf in the first quarter of 2011, 23 percent lower than the comparative period.

Crude Oil

WTI averaged U.S. $94.18 per barrel in the first quarter of 2011, an increase of 20 percent over the first quarter of 2010. As a result of a stronger Cdn. dollar relative to the U.S. dollar and a widening basis differential, Canadian prices were only ten percent higher in 2011 over 2010. Edmonton light averaged $88.12 per barrel in the first quarter of 2011 versus $78.07 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 first 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 low of $1.00 to a high near $0.97 late in the quarter. This negative effect to the price of oil for Canadian producers was compounded by a widening basis differential between U.S. and Canadian markets. In the first quarter of 2011, Canadian crude oil prices averaged $88.12 per barrel compared to $80.07 per barrel in the first quarter of 2010, a ten percent increase over the comparative period.

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 becoming 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 first quarter of 2011 and where was the drilling focused?

The Company had another successful capital program in the first quarter of 2011, drilling 13 gross (10.4 net) wells with a success rate of 100 percent. The drilling was primarily focused on the core property of Wapiti/Gold Creek in North West Alberta with horizontal light oil opportunities pursued in Bigstone and Hythe. 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 March 31, 2011	
	Gross	**Net**
Liquids-rich natural gas wells	**8.0**	**7.2**
Oil wells	**5.0**	**3.2**
Total wells	**13.0**	**10.4**
Success rate (%)	**100**	**100**

CAPITAL INVESTED

How much did the Company spend in the first quarter 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 was $34.1 million, net of drilling credits of $3.9 million, with approximately 72 percent directed at drilling and completion operations and 24 percent incurred on equipping and facility projects. Including the $3.7 million of capital incurred in the fourth quarter starting the program results in a total winter program of approximately $38.3 million.

	Three Months Ended March 31		
	2011	2010	% Change
Land	**232**	2,504	(91)
Seismic	**-**	123	(100)
Drilling and completions	**24,871**	26,982	(8)
Equipping and facilities	**8,259**	4,150	99
Capitalized expenses	**711**	800	(11)
Other	**224**	539	(58)
Capital invested	**34,297**	35,098	(2)
Disposition of properties	**(273)**	-	100
Net capital invested	**34,024**	35,098	(2)
Acquisition of properties	**87**	692	(87)
Total capital invested	**34,111**	35,790	(4)

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 March 31, 2011 averaged 8,259 boe/d, representing an increase of eight percent over the comparative period due to the successful drilling and optimization programs at Bigstone, Hythe and Wapiti/Gold Creek. With the weakness in natural gas pricing, Delphi's 2010/2011 drilling program targeted opportunities in its crude oil and liquids-rich natural gas inventory to maximize netbacks. For the three months ended March 31, 2011, production growth is highlighted by a 74 percent increase in crude oil and natural gas liquids compared to the first 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 year was weighted 74 percent to natural gas, 13 percent to crude oil and 13 percent to natural gas liquids.

	Three Months Ended March 31		
	2011	2010	% Change
Natural gas (mcf/d)	**36,509**	38,349	(5)
Crude oil (bbls/d)	**1,102**	745	48
Natural gas liquids (bbls/d)	**1,072**	508	111
Total (boe/d)	**8,259**	7,645	8

Crude oil production was 48 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.

Natural gas liquids were 111 percent higher for the quarter primarily due to the increased natural gas liquids production in the Wapiti/Gold Creek area where the Company has been successfully drilling multi-zone vertical wells with the Nikanassin formation as the primary target.

Natural gas production was four percent lower compared to the first 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 March 31, 2011, Delphi's risk management program realized a gain of $1.9 million. For the quarter, the realized gain on natural gas contracts was $0.65 per mcf with physical contracts contributing a gain of $0.50 per mcf and financial contracts contributing a gain of $0.15 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. Overall natural gas prices were 26 percent lower in the first quarter of 2011, primarily due to a 23 percent decrease in the price of AECO. For crude oil, the Company lost $2.43 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 13 percent higher in the first quarter of 2011, principally due to a ten percent increase in the price of Canadian benchmark crude prices and an upgrade of the Company's crude quality.

	Three Months Ended March 31		
	2011	2010	% Change
AECO ($/mcf)	**3.80**	4.96	(23)
Heating content and marketing ($/mcf)	**0.17**	0.47	(63)
Gain on physical contracts ($/mcf)	**0.50**	0.83	(41)
Gain on financial contracts ($/mcf)	**0.15**	-	100
Realized natural gas price ($/mcf)	**4.62**	6.26	(26)
Edmonton Light ($/bbl)	**88.12**	80.07	10
Gain (loss) on financial contracts ($/bbl)	**(2.43)**	0.70	-
Quality differential ($/bbl)	**0.60**	(4.49)	-
Realized oil price ($/bbl)	**86.29**	76.28	13
Realized natural gas liquids price ($/bbl)	**54.18**	61.53	(12)
Total realized sales price ($/boe)	**39.23**	42.91	(9)

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. 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. The Company's realized crude oil prices were significantly higher than the comparative period as a result of the increase in benchmark prices and the reduction in quality differential.

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.

	Mar. 31 2011	Dec. 31 2010	Sep. 30 2010	Jun. 30 2010	Mar. 31 2010	Dec. 31 2009	Sept. 30 2009	Jun. 30 2009
Natural Gas Price								
Delphi realized ($/mcf)	**4.62**	5.00	5.28	5.30	6.26	6.15	5.77	5.81
AECO average ($/mcf)	**3.80**	3.64	3.54	3.89	4.96	4.49	2.94	3.47
Premium to AECO	**22%**	37%	49%	36%	26%	37%	96%	67%
Hedging gain ($000's)	**2,126**	4,045	4,676	4,186	2,941	4,498	7,973	6,997

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 60 percent of its before-royalty natural gas production at a predominately AECO based average floor price of $4.81 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 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.

As of May 25, 2011, the Company has fixed the price applicable to future production 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 loss on its financial contracts of $3.3 million in the first three months 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 first three months of 2011 compare to 2010 and what factors contributed to the change?

For the three months ended March 31, 2011, Delphi generated revenue of $28.9 million representing a one percent decrease over the comparative quarter of 2010. The composition of revenue by product changed significantly versus the comparative quarter. In 2011, natural gas revenues accounted for 45 percent of total revenue versus 63 percent in the comparative quarter in 2010. Crude oil and natural gas liquids represented 48 percent of revenue in 2011 versus 27 percent in the same quarter of 2010. The change in mix is a combination of prices received for the products whereby 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 $1.9 million in the first three months of 2011. For ten consecutive quarters, Delphi has received a significant premium to AECO pricing primarily due to the success of the risk management program.

	Three Months Ended March 31		
	2011	2010	% Change
Natural gas	**13,043**	18,650	(30)
Natural gas physical contract gains	**1,622**	2,878	(44)
Crude oil	**8,802**	5,068	74
Natural gas liquids	**5,227**	2,813	86
Sulphur	**206**	47	339
Total	**28,900**	29,456	(1)

ROYALTIES

What were royalty costs in the first three months of 2011?

In the first three months of 2011, the Company paid Crown, freehold and gross overriding royalties. Crown royalties of $4.6 million were partially offset by $1.4 million of royalty credits for processing the Crown’s share of natural gas with the net amount of $3.2 million representing 75 percent of the total royalties paid in the quarter compared to 68 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, the Company’s significant increase in crude oil and natural gas liquids production and several wells coming off reduced royalty rates as part of the Crown’s royalty incentive program.

There were no freehold royalties in the first quarter of 2011 as a result of the disposition of the properties in East Central Alberta in the second quarter of 2010.

Gross overriding royalties represented 25 percent of total royalties in the first quarter of 2011 compared to 30 percent in 2010. The decrease in gross overriding royalties is primarily a result of the lower natural gas prices and the natural decline in production on the wells encumbered by the gross overriding royalties.

	Three Months Ended March 31		
	2011	2010	% Change
Crown royalties	**4,584**	4,732	(3)
Royalty credits	**(1,393)**	(2,124)	(34)
Crown royalties – net	**3,191**	2,608	22
Freehold royalties	**-**	71	(100)
Gross overriding royalties	**1,078**	1,135	(5)
Total	**4,269**	3,814	12
Per boe	**5.74**	5.54	4

What were the average royalty rates paid on production in the first three months of 2011?

The average royalty rates were slightly higher than the comparative period. Crown royalty rates were 19 percent higher primarily as a result of reduced royalty credits in 2011 compared to 2010. Overriding royalties decreased primarily as a result of growth in production from wells not encumbered by an overriding royalty and lower natural gas prices.

	Three Months Ended March 31		
	2011	2010	% Change
Crown rate – net of royalty credits	**11.7%**	9.8%	19
Gross overriding rate	**4.0%**	4.3%	(7)
Average rate	**15.7%**	14.4%	9

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?

Operating costs on a per boe basis for the three months ended March 31, 2011, decreased 16 percent over the comparative period. The decrease is attributed to lower field operating costs as well as increased volumes from the cost efficient core areas of Hythe, Wapiti/Gold Creek and Bigstone. The Company accumulated new and additional infrastructure in its core areas during 2009 which will allow for lower per boe operating costs as production volumes continue to increase. Additionally, the disposition of the East Central Alberta properties in the second quarter of 2010 provided a decrease in absolute costs. Operating costs in the first quarter of 2011 were $6.77 per boe which represents a 22 percent decrease over the $8.70 per boe experienced in 2010. The reduction can be attributed to increased operating efficiencies as a result of facility ownership and reduced equipment rentals in the field.

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.

	Three Months Ended March 31		
	2011	2010	% Change
Production costs	**5,648**	6,562	(14)
Processing income	**(615)**	(577)	7
Total	**5,033**	5,985	(16)
Per boe	**6.77**	8.70	(22)

TRANSPORTATION EXPENSES

	Three Months Ended March 31		
	2011	2010	% Change
Total	**2,212**	2,196	1
Per boe	**2.97**	3.19	(7)

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

On a per boe basis, transportation costs for the three months ended March 31, 2011, decreased by seven percent over the comparative period. The decrease in transportation costs per boe is primarily due to the growth in production volumes resulting in the allocation of fixed transportation costs over more volumes.

GENERAL AND ADMINISTRATIVE

	Three Months Ended March 31		
	2011	2010	% Change
General and administrative costs	**2,653**	2,548	4
Overhead recoveries	**(451)**	(555)	(19)
Salary allocations	**(994)**	(859)	16
Net	**1,208**	1,133	7
Per boe	**1.63**	1.65	(1)

How do general and administrative costs in the first quarter of 2011 compare to 2010?

On a per boe basis, general and administrative (G&A) costs were down by one percent. An increase in costs of seven percent was offset by growth in production volumes resulting in costs per boe remaining the same. 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 March 31		
	2011	2010	% Change
Share-based compensation	**180**	197	(40)
Capitalized costs	**(14)**	(104)	(87)
Net	**166**	93	78
Per boe	**0.22**	0.14	57

The share-based non-cash compensation expense for the three months ended March 31, 2011, increased 78 percent over the comparative period. The increase is attributed to additional stock options granted to new employees. During the three months ended March 31, 2011, Delphi capitalized $14,000 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 months ended March 31, 2011, interest costs increased three percent over the comparative period.

	Three Months Ended March 31		
	2011	2010	% Change
Interest	**1,380**	1,342	3
Accretion	**141**	138	(2)
Total	**1,521**	1,480	(3)
Interest per boe	**1.86**	1.95	(5)
Accretion per boe	**0.19**	0.20	(5)

During 2009, the Company converted $80.0 million of its outstanding long term debt from prime-based loans to bankers' acceptances. At March 31, 2011, the bankers' acceptances have terms ranging from 88 to 182 days and a weighted average effective interest rate of 4.24 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 three 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 March 31, 2011 decreased two percent over the comparative period.

DEPLETION AND DEPRECIATION

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

Depletion and depreciation per boe for the three months ended March 31, 2011 decreased two percent over the comparative period, excluding the impairment loss. 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.

At March 31, 2010, the Company recorded an impairment loss of $5.0 million on a non-core cash generating unit as a result of declining natural gas prices.

	Three Months Ended March 31		
	2011	2010	% Change
Depletion and depreciation	**10,601**	9,968	(6)
Impairment loss	**-**	5,000	(100)
Total	**10,601**	14,968	(29)
Per boe	**14.26**	21.75	(34)

INCOME TAXES

What was the affect on future income taxes as a result of the loss in the year?

The provision for future income taxes in the financial statements for the three months ended March 31, 2011 was an expense of $0.2 million. Delphi does not anticipate it will be cash taxable before 2014.

	Three Months Ended March 31		
	2011	2010	% Change
Current	**-**	-	
Future (reduction)	**211**	1,376	(85)
Total	**211**	1,376	(85)
Per boe	**0.28**	2.00	(86)

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, deferred income taxes and unrealized gain (loss) on the fair value of financial instruments) and excludes the change in non-cash working capital related to operating activities and expenditures on decommissioning obligations. Delphi uses funds from operations ("cash flow") 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 first three months of 2011 compare to 2010?

For the three months ended March 31, 2011, funds from operations were $15.1 million ($0.13 per basic share) compared to $14.8 million ($0.15 per basic share) in the comparative period. The increase in funds from operations is primarily a result of an increase in production volumes and a reduction in operating costs, offsetting higher royalties and a lower realized sales price per boe.

	Three Months Ended March 31		
	2011	2010	% Change
Net earnings (loss)	**962**	1,613	(40)
Non-cash items:			
Depletion, depreciation	**10,601**	14,722	(29)
Accretion of decommissioning obligations	**141**	384	2
Gain on disposition	**(273)**	-	(100)
Unrealized loss on risk management activities	**3,253**	(3,437)	-
Stock-based compensation expense	**166**	93	78
Future income tax reduction	**211**	1,376	(85)
Funds from operations	**15,061**	14,751	5

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 and changes in non-cash operating working capital. The following table is a reconciliation of funds from operations to cash flow from operating activities for the three months ended March 31, 2011 and 2010.

	Three Months Ended March 31		
	2011	2010	% Change
Funds from operations: Non-IFRS	**15,061**	14,751	2
Accretion of long term debt	**463**	-	-
Change in non-cash working capital	**(3,506)**	(4,028)	(13)
Cash flow from operating activities: IFRS	**12,018**	10,723	12

NET EARNINGS

What factors contributed to the loss in the first three months of 2011?

For the three months ended March 31, 2011, Delphi recorded net earnings of $1.0 million ($0.01 per basic share). Net earnings were affected by non-cash items such as depletion, depreciation and accretion, unrealized gains on risk management activities, stock-based compensation 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 first quarter of 2011 compare to the prior period?

For 2011, the Company's netbacks were lower by seven percent principally due to a lower realized sales price per boe. 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 flow netback per boe.

	Three Months Ended March 31		
	2011	2010	% Change
Barrels of oil equivalent ($/boe)			
Realized sales price	**39.23**	42.91	(9)
Royalties	**5.74**	5.54	4
Operating expenses	**6.77**	8.70	(22)
Transportation	**2.97**	3.19	(7)
Operating netback	**23.75**	25.48	(7)
General and administrative expenses	**1.63**	1.65	(1)
Interest	**1.86**	1.95	(5)
Cash netback	**20.26**	21.88	(7)
Unrealized loss on financial contracts	**4.38**	(5.00)	-
Stock-based compensation expense	**0.22**	0.14	57
Depletion and depreciation	**14.26**	21.75	(34)
Accretion	**0.19**	0.20	(5)
Future income taxes reduction	**0.28**	2.00	(86)
Net earnings	**0.93**	2.79	(67)

SELECTED INFORMATION

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

Over the last eight quarters production has grown from 6,762 boe/d to 8,259 boe/d. Production for the last eight quarters reflects the following events. In the first six months of 2009, production growth was achieved with drilling success at Bigstone and Hythe, Alberta, primarily focused on natural gas opportunities. 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.

Over the past two years, the changes in revenue and cash flow 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. 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.

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	*GAAP*	*GAAP*	*GAAP*	*IFRS*	*GAAP*	*GAAP*	*GAAP*
	Mar. 31 2011	Dec. 31 2010	Sep. 30 2010	Jun. 30 2010	Mar. 31 2010	Dec. 31 2009	Sept. 30 2009	Jun. 30 2009
Production								
Natural gas (mcf/d)	**36,509**	38,918	39,439	38,540	38,349	34,626	33,628	35,641
Oil (bbls/d)	**1,102**	1,147	831	1,074	745	630	624	371
Natural gas liquids (bbls/d)	**1,072**	906	710	538	508	487	544	498
Barrels of oil equivalent (boe/d)	**8,259**	8,539	8,114	8,035	7,645	6,888	6,773	6,809
Financial								
($ thousands except per unit amounts)								
Petroleum and natural gas revenue	**28,900**	30,475	28,080	29,125	29,519	26,297	24,433	23,229
Funds from operations (cash flow)	**15,061**	17,987	15,120	12,988	14,751	14,218	12,635	12,371
Per share – basic	**0.13**	0.16	0.13	0.12	0.15	0.14	0.16	0.16
Per share – diluted	**0.13**	0.16	0.13	0.12	0.15	0.14	0.16	0.16
Net earnings (loss)	**962**	204	(1,566)	(2,742)	1,613	1,386	(3,278)	(2,817)
Per share – basic	**0.01**	-	(0.01)	(0.03)	0.02	0.02	(0.04)	(0.04)
Per share – diluted	**0.01**	-	(0.01)	(0.03)	0.02	0.02	(0.04)	(0.04)

LIQUIDITY AND CAPITAL RESOURCES

Share Capital

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

At March 31, 2011, the Company had 117.1 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 months ended March 31, 2011.

	Three Months Ended March 31, 2011
Weighted Average Common Shares	
Basic	113,465
Diluted	115,703
Trading Statistics (1)	
High	2.59
Low	2.02
Average daily volume	825,266

(1) Trading statistics based on closing price

How many common shares and stock options are currently outstanding?

As at May 24, 2011, the Company had 117.5 million common shares outstanding and 6.8 milllion stock options outstanding. The stock options have an average exercise price of $1.74 per share.

Sources and Uses of Funds

	Three Months Ended March 31, 2011
Sources:	
Funds from operations	15,061
Disposition of petroleum and natural gas properties	273
Acquisition of petroleum and natural gas properties	-
Issue of flow-through common shares, net of issue costs	8,946
Exercise of stock options	1,279
Accretion of long term debt	463
Change in non-cash working capital	11,884
	37,906
Uses:	
Cash and cash equivalents	3,522
Capital expenditures	34,297
Acquisition of petroleum and natural gas properties	87
	37,906
Change in long term debt	-

Bank Debt plus Working Capital Deficiency (Net Debt)

How much bank debt was outstanding on March 31, 2011?

At December 31, 2010, the Company had $79.5 million outstanding in the form of bankers' acceptances, $25.0 million drawn under Canadian-based prime loans and a working capital deficiency of $12.4 million for total net debt of $116.9 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 March 31, 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	3,477	4,262	3,451	2,990	2,958
Office and equipment lease	1,355	775	390	-	-
Total	4,832	5,037	3,841	2,990	2,958

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 financial statements, is Delphi required to make estimates or assumptions about future events?

The condensed consolidated interim 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 these condensed consolidated interim financial statements, the significant judgments made by management 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. Information about these judgments, estimates and assumptions that have the most significant effect on the amounts recognized in the consolidated financial statements is included in the following notes to the financial statements:

i) Note 5 - valuation of financial instruments;
ii) Note 8 - valuation of exploration and evaluation assets;
iii) Note 9 - valuation of property, plant and equipment;
iv) Note 11 – measurement of decommissioning obligations; and
v) Note 12 - 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 first quarter ended March 31, 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 15 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 call joint ventures, from IAS 31 "Interests in Joint Ventures" 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

Overview

The shareholders' interests are a critical factor in the operations and management of Delphi. The Company is committed to maintaining the highest level of investor confidence in the Company through the application of its corporate policies and procedures. Delphi's Board of Directors consists of six independent directors and two officers of the Company who meet regularly to discuss matters of strategy and execution of the business plan. See Delphi's Management Information Circular and Annual Information Form for a listing of committees that oversee specific aspects of the Company's operating and financial strategy.

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)	**March 31 2011**	December 31 2010	January 1 2010
(unaudited)		(Note 15)	(Note 15)
Assets			
Current assets			
Cash	**7,561**	4,039	-
Accounts receivable	**21,585**	17,897	15,630
Prepaid expenses and deposits	**2,977**	3,426	6,004
Assets held for sale (Note 7)	**-**	-	2,804
Fair value of financial instruments (Note 5)	**496**	2,080	104
	32,619	27,442	24,542
Exploration and evaluation assets (Note 8)	**3,043**	2,787	315
Property, plant and equipment (Note 9)	**381,017**	357,458	332,938
Total assets	**416,679**	387,687	357,795
Liabilities			
Current liabilities			
Outstanding cheques	**-**	-	139
Accounts payable and accrued liabilities	**44,489**	28,416	32,933
Liabilities held for sale (Note 7)	**-**	-	2,554
Fair value of financial instruments (Note 5)	**1,108**	-	-
	45,597	28,416	35,626
Other liability (Note 12)	**800**	-	960
Long term debt (Note 10)	**104,513**	105,000	81,100
Decommissioning obligations (Note 11)	**17,378**	17,232	15,496
Fair value of financial instruments (Note 5)	**4,088**	3,527	485
Deferred income taxes	**16,776**	16,552	21,144
	189,152	170,727	154,811
Shareholders' equity			
Share capital (Note 12)	**246,480**	236,382	206,382
Contributed surplus	**11,494**	11,987	11,027
Deficit	**(30,447)**	(31,409)	(14,425)
Total shareholders' equity	**227,527**	216,960	202,984
Total liabilities and shareholders' equity	**416,679**	387,687	357,795

See accompanying notes to the interim consolidated financial statements.

DELPHI ENERGY CORP.

Consolidated Statements of Earnings and Comprehensive Earnings
For the three months ended March 31

(thousands of dollars, except per share amounts)	**2011**	2010
(unaudited)		(Note 15)
Revenue		
Crude oil and natural gas sales	**28,900**	29,456
Royalties	**(4,269)**	(3,814)
	24,631	25,642
Realized gain on financial instruments (Note 5)	**263**	63
Unrealized gain (loss) on financial instruments (Note 5)	**(3,253)**	3,437
	21,641	29,142
Expenses		
Operating	**5,033**	5,985
Transportation	**2,212**	2,196
Exploration and evaluation	**-**	298
General and administrative	**1,208**	1,133
Share-based compensation (Note 12)	**166**	93
Gain on disposition	**(273)**	-
Depletion and depreciation (Note 9)	**10,601**	14,968
	18,947	24,673
Finance costs (Note 13)	**(1,521)**	(1,480)
Earnings before taxes	**1,173**	2,989
Taxes		
Deferred income taxes	**211**	1,376
Net earnings and comprehensive earnings	**962**	1,613
Net earnings per share (Note 12)		
Basic	**0.01**	0.02
Diluted	**0.01**	0.02

See accompanying notes to the interim consolidated financial statements.

DELPHI ENERGY CORP.

Consolidated Statements of Changes in Shareholders' Equity
For the three months ended March 31, 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	-	-	1,613	1,613
Issued on exercise of options	338	-	-	338
Share-based compensation on exercise of options	177	(177)	-	-
Share-based compensation expense	-	93	-	93
Share-based compensation expense capitalized	-	104	-	104
Balance as at March 31, 2010	206,897	11,047	(12,812)	205,132

(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	-	-	962	962
Issue of flow-through common shares	8,160	-	-	8,160
Share issue costs	(14)	-	-	(14)
Issued on exercise of options	1,279	-	-	1,279
Share-based compensation on exercise of options	673	(673)	-	-
Share-based compensation expense	-	166	-	166
Share-based compensation capitalized	-	14	-	14
Balance as at March 31, 2011	**246,480**	**11,494**	**(30,447)**	**227,527**

See accompanying notes to the interim consolidated financial statements.

DELPHI ENERGY CORP.

Consolidated Statements of Cash Flows
For the three months ended March 31

(thousands of dollars)	**2011**	2010
(unaudited)		(Note 15)
Cash flow from (used in) operating activities		
Net earnings	**962**	1,613
Add non-cash items:		
Depletion and depreciation	**10,601**	14,968
Accretion of decommissioning obligations	**141**	138
Accretion of long term debt	**463**	-
Share-based compensation	**166**	93
Gain on disposition	**(273)**	-
Unrealized loss (gain) on financial instruments	**3,253**	(3,437)
Deferred income taxes	**211**	1,376
Change in non-cash working capital (Note 14)	**(3,506)**	(4,028)
	12,018	10,723
Cash flow from (used in) financing activities		
Issue of flow-through common shares, net of issue costs	**8,946**	-
Exercise of stock options	**1,279**	338
Decrease in long term debt	**-**	(1,100)
	10,225	(762)
Cash flow available for investing activities	**22,243**	9,961
Cash flow from (used in) investing activities		
Additions to exploration and evaluation assets	**(256)**	(2,269)
Additions to property, plant and equipment	**(34,041)**	(32,829)
Disposition of petroleum and natural gas properties	**273**	-
Acquisition of petroleum and natural gas properties	**(87)**	(692)
Change in non-cash working capital (Note 14)	**15,390**	20,698
	(18,721)	(15,092)
Increase (decrease) in cash and cash equivalents	**3,522**	(5,131)
Cash and cash equivalents, beginning of period	**4,039**	(139)
Cash and cash equivalents, end of period	**7,561**	(5,270)
Cash interest paid	**1,415**	1,396

See accompanying notes to the interim consolidated financial statements.

DELPHI ENERGY CORP.

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 months ended March 31, 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 Canadian GAAP ("previous 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 first 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 position, financial performance and cash flows of the Company is provided in note 15. This note includes reconciliations of equity and total comprehensive earnings for comparative periods and of equity at the date of transition reported under previous GAAP to those reported for those periods and at the date of transition under IFRS.

These interim consolidated financial statements were approved by the Board of Directors on May 25, 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. Information about these judgments, estimates and assumptions that have the most significant effect on the amounts recognized in the consolidated financial statements is included in the following notes:

vi) Note 5 - valuation of financial instruments;
vii) Note 8 - valuation of exploration and evaluation assets;
viii) Note 9 - valuation of property, plant and equipment;
ix) Note 11 – measurement of decommissioning obligations; and
x) Note 12 - measurement of share-based compensation.

Estimates of proved plus probable reserves have an affect 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.

3) SIGNIFICANT ACCOUNTING POLICIES

The accounting policies set out below 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) Basis of consolidation

Business combinations on or after January 1, 2010

For business combinations on or after January 1, 2010, the Company measures goodwill at the acquisition date as the fair value of the consideration transferred including the recognized amount of any non-controlling interests in the acquiree, less the net recognized amount (generally fair value) of the identifiable assets acquired and liabilities assumed, all measured as of the acquisition date. When the excess is negative, a bargain purchase gain is recognized immediately in the consolidated statement of earnings. The acquisition date is the closing date of the business combination.

The Company elects on a transaction-by-transaction basis whether to measure non-controlling interests at fair value, or at their proportionate share of the recognized amount of the identifiable net assets, at the acquisition date. Transaction costs, other than those associated with the issue of debt and equity securities, that the Company incurs in connection with a business combination are expensed as incurred.

Business combinations prior to January 1, 2010

As part of its transition to IFRS, the Company elected to restate only those business combinations that occurred on or after January 1, 2010.

i) Subsidiaries

Subsidiaries are entities controlled by the Company. Control exists when the Company has the power to govern the financial and operating policies of an entity so as to obtain benefits from its activities. In assessing control, potential voting rights that currently are exercisable are taken into account. The financial statements of subsidiaries are included in the consolidated financial statements from the date that control commences until the date that control ceases.

ii) Jointly controlled operations

Certain of the Company's crude oil and natural gas activities involve jointly controlled operations. The consolidated financial statements reflect the Company's proportionate share of the jointly controlled assets and liabilities and proportionate share of related revenues and costs.

iii) Transactions eliminated on consolidation

Inter-company balances and transactions and any unrealized income and expenses arising from inter-company transactions are eliminated in preparing the consolidated financial statements.

(b) Foreign currency transactions

Transactions in foreign currencies are translated to Canadian dollars at the exchange rate on the date of the transactions. Monetary assets and liabilities denominated in foreign currencies are translated to Canadian dollars at the period end exchange rate. Foreign currency differences arising on translation are recognized in the consolidated statement of earnings.

(c) Financial instruments

i) Non-derivative financial assets

The Company initially recognizes loans and receivables on the date that they are originated. All other financial assets (including assets designated at fair value through profit or loss) are recognized initially on the trade date at which the Company becomes a party to the contractual provisions of the instrument.

The Company derecognizes a financial asset when the contractual rights to the cash flows from the asset expire or if it transfers the rights to receive the contractual cash flows on the financial asset in a transaction in which substantially all the risk and rewards of ownership of the financial asset are transferred. Any interest in transferred financial assets that is created or retained by the Company is recognized as a separate asset or liability.

Financial assets and liabilities are offset and the net amount presented in the consolidated statement of financial position when, and only when, the Company has the legal right to offset the amounts and intends either to settle on a net basis or to realize the asset and settle the liability simultaneously.

The Company classifies non-derivative financial assets into the following categories: financial assets at fair value through profit or loss, held-to-maturity financial assets, loans and receivables and available-for-sale financial assets.

Financial assets at fair value though profit or loss
A financial asset is classified at fair value through profit or loss if it is classified as held for trading or is designated as such upon initial recognition. Financial assets are designated at fair value through profit or loss if the Company manages such investments and makes purchase and sales decisions based on their fair value in accordance with the Company's documented risk management or investment strategy. Attributable transaction costs are recognized in the consolidated statement of earnings as incurred. Financial assets at fair value through profit or loss are measured at fair value and changes therein are recognized in the consolidated statement of earnings.

Loans and receivables
Loans and receivables are financial assets with fixed or determinable payments that are not quoted in an active market. Such assets are recognized initially at fair value plus any directly attributable transaction costs. Subsequent to initial recognition, loans and receivables are measured at amortized cost using the effective interest rate method less any loss due to impairment.

Loans and receivables consist of accounts receivable.

Cash and cash equivalents
Cash and cash equivalents consist of cash balances, call deposits with original maturities of three months or less and outstanding cheques.

ii) Non-derivative financial liabilities

The Company initially recognizes debt securities issued and subordinated liabilities on the date that they are originated. All other financial liabilities (including liabilities designated at fair value through profit or loss) are recognized initially on the trade date at which the Company becomes a party to the contractual provisions of the instrument.

The Company derecognizes a financial liability when its contractual obligations are discharged, cancelled or expired.

Financial assets and liabilities are offset and the net amount presented in the consolidated statement of financial position when, and only when, the Company has the legal right to offset the amounts and intends either to settle on a net basis or to realize the asset and settle the liability simultaneously.

The Company classifies non-derivative financial liabilities into the other financial liabilities category. Such financial liabilities are initially recognized at fair value plus any directly attributable transaction costs. Subsequent to initial recognition, these financial liabilities are measured at amortized cost using the effective interest rate method.

Other financial liabilities consist of accounts payable and accrued liabilities and long term debt.

Bank overdrafts that are repayable on demand and form an integral part of the Company's cash management are included as a component of cash and cash equivalents for the purpose of the consolidated statement of cash flows.

iii) Derivative financial instruments

The Company has a risk management program whereby the commodity price associated with a portion of its future production volumes is fixed in order to mitigate cash flow volatility resulting from fluctuating commodity prices. The Company sells forward a portion of its future production volumes by entering into a combination of physical sale contracts with customers and derivative financial contracts with financial counterparties. These instruments are not used for trading or speculative purposes.

The Company has elected not to designate its derivative financial contracts as effective hedges and hence hedge accounting has not been applied to these contracts. Derivative financial contracts are initially recognized at fair value with attributable transaction costs recognized in the consolidated statement of earnings when incurred. Subsequent to initial recognition, the derivatives are measured at fair value with all changes in fair value being recorded in the consolidated statement of earnings.

The Company has accounted for its physical commodity 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. As such, these contracts are not considered to be derivative financial instruments and have not been recorded at fair value on the balance sheet. Settlements on these physical sales contracts are recognized in crude oil and natural gas sales in the consolidated statement of earnings.

Embedded derivatives are separated from the host contract and accounted for separately if 1) the economic characteristics and risks of the host contract and the embedded derivative are not closely related, 2) a separate instrument with the same terms as the embedded derivative would meet the definition of a derivative and 3) the combined instrument is not measured at fair value through profit or loss. Changes in the fair value of embedded derivatives are recognized in the consolidated statement of earnings.

iv) Share capital

Common shares are classified as equity. Incremental costs directly attributable to the issue of common shares and share options are recognized as a deduction from equity, net of any taxes.

(d) Property, plant and equipment and exploration and evaluation assets

i) Recognition and measurement

Pre-licence costs are recognized in the consolidated statement of earnings as the costs are incurred.

Exploration and evaluation costs
Exploration and evaluation costs, including the costs of acquiring licences and directly attributable general and administrative costs, are initially capitalized as exploration and evaluation assets. The costs are accumulated in cost centres by well, field or exploration area pending determination of technical feasibility and commercial viability.

Exploration and evaluation assets (E&E) are assessed for impairment if 1) sufficient data exists to determine technical feasibility and commercial viability and 2) facts and circumstances suggest that the carrying amount exceeds the recoverable amount.

The technical feasibility and commercial viability of extracting a mineral resource is considered to be determinable when proved plus probable reserves are determined to exist. A review of each exploration licence or field is carried out, at least annually, to ascertain whether proved plus probable reserves have been discovered. Upon determination of total proved plus probable reserves, exploration and evaluation assets attributable to those reserves are first tested for impairment and then reclassified from exploration and evaluation assets to property, plant and equipment.

Development and production costs
Items of property, plant and equipment, which include crude oil and natural gas development and production assets, are measured at cost less accumulated depletion and depreciation and accumulated impairment losses. The development and production assets are grouped into cash generating units (CGU) for the purpose of impairment testing. The cost of property, plant and equipment as at January 1, 2010, the date of transition, was allocated to the CGU's based on geographical location and the related field processing and transportation infrastructure. Within a CGU, when significant parts of property, plant and equipment have different useful lives, the parts are accounted for as separate items (major components) of property, plant and equipment.

Gains and losses on the disposition of property, plant and equipment, including crude oil and natural gas interests, are determined by comparing the proceeds from disposition with the carrying amount of the property, plant and equipment and are recognized on a net basis in the consolidated statement of earnings.

ii) Subsequent costs

Costs incurred subsequent to the determination of technical feasibility and commercial viability and the costs of replacing parts of property, plant and equipment are recognized as crude oil and natural gas interests only when the costs increase the future economic benefits embodied in the specific asset to which they relate. All other expenditures are recognized in the consolidated statement of earnings as incurred. Such capitalized oil and natural gas interests generally represent costs incurred in developing proved or proved plus probable reserves and bringing on or enhancing production from such reserves and are accumulated on a field or geotechnical area basis. The carrying amount of any replaced or sold component is derecognized. The costs of the day-to-day servicing of property, plant and equipment are recognized in the consolidated statement of earnings as incurred.

iii) Depletion and depreciation

The net carrying amount of development and production assets is depleted using the unit-of-production method by reference to the ratio of production in the period to the related proved plus probable reserves, taking into account estimated future development costs necessary to bring those reserves into production. Future development costs are estimated taking into account the level of development required to produce the reserves. These estimates are reviewed by independent reserve engineers at least annually.

Proved and probable reserves are estimated using independent reserve engineer reports and represent the estimated quantities of crude oil, natural gas and natural gas liquids which geological, geophysical and engineering data demonstrate with a specified degree of certainty to be recoverable in future years from known reservoirs and which are considered commercially producible. There should be a 50 percent statistical probability that the actual quantity of recoverable reserves will be more than the amount estimated as proved and probable and a 50 percent statistical probability that it will be less. The equivalent statistical probabilities for the proved component of proved and probable reserves are 90 percent and 10 percent, respectively.

Such reserves may be considered commercially producible if management has the intention of developing and producing them and such intention is based upon 1) a reasonable assessment of the future economics of such production, 2) a reasonable expectation that there is a market for all or substantially all the expected crude oil and natural gas production and 3) evidence that the necessary production, transmission and transportation facilities are available or can be made available.

Reserves may only be considered proved and probable if producibility is supported by either actual production or a conclusive formation test. The area of reservoir considered proved includes 1) that portion delineated by drilling and defined by gas-oil and/or oil-water contacts, if any, or both, and 2) the immediately adjoining portions not yet drilled, but which can be reasonably judged as economically productive on the basis of available geophysical, geological and engineering data. In the absence of information on fluid contacts, the lowest known structural occurrence of crude oil and natural gas controls the lower proved limit of the reservoir.

Reserves which can be produced economically through application of improved recovery techniques (such as fluid injection) are only included in the proved and probable classification when successful testing by a pilot project, the operation of an installed program in the reservoir or other reasonable evidence (such as experience of the same techniques on similar reservoirs or reservoir simulation studies) provides support for the engineering analysis on which the project or program was based.

The estimated useful lives for certain production assets for the current and comparative periods are as follows:

Facilities	33 years
Crude oil and natural gas properties	Based on CGU reserve life

For other assets, depreciation is recognized in the consolidated statement of earnings on a declining balance basis over the estimated useful lives of each part of an item of property, plant and equipment. Leased assets are depreciated over the shorter of the lease term and their useful lives unless it is reasonably certain that the Company will obtain ownership by the end of the lease term.

The estimated useful lives for other assets for the current and comparative periods are as follows:

Furniture and office equipment	5 years
Leaseholds	Term of the lease

Depreciation methods, useful lives and residual values are reviewed at each reporting date.

(e) Impairment

(i) Financial assets

A financial asset is assessed at each reporting date to determine whether there is any objective evidence that it is impaired. A financial asset is considered to be impaired if objective evidence indicates that one or more events have had a negative effect on the estimated future cash flows of that asset.

An impairment loss in respect of a financial asset measured at amortized cost is calculated as the difference between its carrying amount and the present value of the estimated future cash flows discounted at the original effective interest rate.

Individually significant financial assets are tested for impairment on an individual basis. The remaining financial assets are assessed collectively in groups that share similar credit risk characteristics.

All impairment losses are recognized in the consolidated statement of earnings.

An impairment loss is reversed if the reversal can be related objectively to an event occurring after the impairment loss was recognized. For financial assets measured at amortized cost the reversal is recognized in the consolidated statement of earnings.

(ii) Non-financial assets

The carrying amount of property, plant and equipment is reviewed at each reporting date to determine whether there is any indication of impairment. If any such indication exists, then the asset's recoverable amount is estimated. E&E assets are assessed for impairment when they are reclassified to property, plant and equipment, as crude oil and natural gas interests, and also when facts and circumstances suggest that the carrying amount exceeds the recoverable amount.

For the purpose of impairment testing, assets are grouped together into the smallest group of assets that generate cash inflows from continuing use that are largely independent of the cash inflows of other assets or groups of assets, the CGU. The recoverable amount of an asset or a CGU is the greater of its value in use and its fair value less costs to sell.

In assessing value in use, the estimated future cash flows are discounted to their present value using a pre-tax discount rate that reflects current market assessments of the time value of money and the risks specific to the asset. Value in use is generally computed by reference to the present value of the future cash flows expected to be derived from production of proved and probable reserves.

An impairment loss is recognized if the carrying amount of an asset or its CGU exceeds its estimated recoverable amount. Impairment losses are recognized in the consolidated statement of earnings. Impairment losses recognized in respect of CGU's are allocated to reduce the carrying amounts of the assets in the unit on a pro rata basis.

Impairment losses in respect of property, plant and equipment and exploration and evaluation assets recognized in prior years are assessed at each reporting date for any indications that the loss has decreased or no longer exists. An impairment loss is reversed if there has been a change in the estimates used to determine the recoverable amount. An impairment loss is reversed only to the extent that the asset's carrying amount does not exceed the carrying amount that would have been determined, net of depletion and depreciation, if no impairment loss had been recognized.

(f) Share-based compensation

Long-term incentives are granted to officers, directors, employees and certain consultants in accordance with the Company's stock option plan.

The fair value of stock options is assessed on the grant date using the Black-Scholes option pricing model. The fair value is subsequently recognized as compensation expense over the vesting period with a corresponding increase in contributed surplus. Upon exercise of the options, consideration paid by the stock option holders and the value in contributed surplus pertaining to the exercised options are recorded as share capital.

A forfeiture rate is estimated on the grant date wih the difference between the estimated and actual forfeitures adjusted through share-based compensation.

(g) Lease payments

Payments made under operating leases are recognized in the consolidated statement of earnings on a straight-line basis over the term of the lease. Lease incentives received are recognized as an integral part of the total lease expense over the term of the lease.

(h) Provisions

A provision is recognized if, as a result of a past event, the Company has a present legal or constructive obligation that can be estimated reliably, and it is probable that an outflow of economic benefits will be required to settle the obligation. Provisions are determined by discounting the expected future cash flows at a pre-tax rate that reflects current market assessments of the time value of money and the risks specific to the liability. Provisions are not recognized for future operating losses.

(i) Decommissioning obligations

The Company's activities give rise to dismantling, decommissioning and site disturbance remediation activities. Provision is made for the estimated cost of site restoration and capitalized in the relevant asset category.

Decommissioning obligations are measured at the present value of management's best estimate of the expenditure required to settle the present obligation at the balance sheet date. Subsequent to the initial measurement, the obligation is adjusted at the end of each period to reflect the passage of time and changes in the estimated future cash flows underlying the obligation. The increase in the provision due to the passage of time is recognized as finance costs whereas increases/decreases due to changes in the estimated future cash flows are capitalized. Actual costs incurred upon settlement of the asset retirement obligations are charged against the provision to the extent the provision was established.

(j) Flow-through shares

Resource expenditures for income tax purposes related to exploration and development activities funded by flow-through share arrangements are renounced to investors in accordance with income tax legislation. A liability is recognized for the premium on the flow-through shares and is subsequently reversed as the Company incurs qualifying expenditures. Any difference between the deferred liability set up for the premium on the flow-through shares and the tax effect on the qualifying expenditures incurred is recognized in the consolidated statement of earnings.

(k) Revenues

Revenues from the sale of crude oil and natural gas are recorded when the significant risks and rewards of ownership of the product is transferred to the buyer which is usually when legal title passes to the external party. This is generally at the time product enters the pipeline.

Royalty income is recognized as it accrues in accordance with the terms of the overriding royalty agreements.

(l) Finance income and costs

Finance costs comprises interest expense on borrowings and accretion of the discount on provisions and decommissioning obligations.

Foreign currency gains and losses, reported under finance income and costs, are reported on a net basis.

(m) Income tax

Income tax expense comprises current and deferred tax. Income tax expense is recognized in the consolidated statement of earnings except to the extent that it relates to a business combination or items recognized directly in equity, in which case it is recognized in equity or other comprehensive income.

Current tax is the expected tax payable on the taxable income for the period, using tax rates enacted or substantively enacted at the reporting date and any adjustment to tax payable in respect of previous years.

Deferred taxes are recognized using the balance sheet method, providing for temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for taxation purposes. Deferred taxes are not recognized on the initial recognition of assets or liabilities in a transaction that is not a business combination. In addition, deferred taxes are not recognized for taxable temporary differences arising on the initial recognition of goodwill. Deferred taxes are measured at the tax rates that are expected to be applied to temporary differences when they reverse, based on the laws that have been enacted or substantively enacted by the reporting date. Deferred tax assets and liabilities are offset if there is a legally enforceable right to offset, and they relate to income taxes levied by the same tax authority on the same taxable entity, or on different tax entities, but they intend to settle current tax liabilities and assets on a net basis or their tax assets and liabilities will be realized simultaneously.

A deferred tax asset is recognized for unused tax losses, tax credits and deductible temporary differences to the extent that it is probable that future taxable profits will be available against which the temporary differences can be utilized. Deferred tax assets are reviewed at each reporting date and are reduced to the extent that it is no longer probable that the related tax benefit will be realized.

(n) Earnings per share

Basic earnings per share is calculated by dividing the net earnings or loss attributable to common shareholders of the Company by the weighted average number of common shares outstanding during the period. Diluted earnings per share is determined by adjusting the net earnings or loss attributable to common shareholders and the weighted average number of common shares outstanding for the effects of dilutive instruments such as options granted to employees.

4) DETERMINATION OF FAIR VALUES

A number of the Company's accounting policies and disclosures require the determination of fair value, for both financial and non-financial assets and liabilities. When applicable, further information about the assumptions made in determining fair values is disclosed in the notes specific to that asset or liability. Fair values have been determined for measurement and/or disclosure purposes based on the following methods.

(a) Property, plant and equipment and intangible exploration assets:

The fair value of property, plant and equipment and exploration and evaluation assets recognized in a business combination, is based on market values. The market value of property, plant and equipment and exploration and evaluation assets is the estimated amount for which the assets could be exchanged on the acquisition date between a willing buyer and a willing seller in an arm's length transaction after proper marketing wherein the parties had each acted knowledgeably, prudently and without compulsion. The market value of crude oil and natural gas interests (included in property, plant and equipment) is estimated with reference to the discounted cash flows expected to be derived from crude oil and natural gas production based on externally prepared reserve reports. The risk-adjusted discount rate is specific to the asset with reference to general market conditions.

The market value of other items of property, plant and equipment is based on the quoted market prices for similar items.

(b) Cash and cash equivalents, accounts receivable, accounts payable and accrued liabilities and long term debt:

The fair value of cash and cash equivalents, accounts receivable, accounts payable and accrued liabilities and long term debt is estimated as the present value of future cash flows, discounted at the market rate of interest at the reporting date. At March 31, 2011 and December 31, 2010, the fair value of these balances approximated their carrying value due to their short term to maturity or in the case of long term debt, the fair value approximates its carrying value as it bears interest at floating rates and the applicable margin was indicative of the Company's current credit premium.

(c) Derivatives:

The fair value of forward contracts and swaps is determined by discounting the difference between the contracted prices and published forward price curves as at the reporting date, using the remaining contracted crude oil and natural gas volumes and a risk-free interest rate (based on published government rates). The fair value of options and costless collars is based on option models that use published information with respect to volatility, prices and interest rates. The Company's derivative financial contracts are transacted in active markets. The contracts are measured at fair values that are classified as Level 2 in accordance with the following hierarchy.

Level 1 – Quoted prices are available in active markets for identical assets or liabilities as of the reporting date. Active markets are those in which transactions occur in sufficient frequency and volume to provide pricing information on an ongoing basis.

Level 2 – Valuations are based on inputs, including quoted forward prices for commodities, time value and volatility factors which can be substantially observed or corroborated in the marketplace.

Level 3 – Valuations in this level are those with inputs for the asset or liability that are not based on observable market data.

(d) Share-based compensation:

The fair value of employee stock options is measured using a Black-Scholes option pricing model. Measurement inputs include the share price on measurement date, exercise price of the instrument, expected volatility (based on weighted average historic volatility adjusted for changes expected due to publicly available information), weighted average expected life of the instruments (based on historical experience and general option holder behaviour), expected dividends and the risk-free interest rate (based on government bonds).

5) FINANCIAL RISK MANAGEMENT

The Company is exposed to credit, market and liquidity risks from its use of financial instruments. This note provides information about the Company's exposure to each of the above risks and the Company's policies and processes for measuring and managing risk. Risk management is ultimately established by the Board of Directors and is implemented and monitored by senior management.

(a) Commodity price risk

Commodity price risk is the risk that the future cash flows will fluctuate as a result of changes in commodity prices. Commodity prices for crude oil and natural gas are affected not only by world economic events that dictate the levels of supply and demand but also the relationship between the Canadian and United States ("US") dollar, as outlined below. The Company has a commodity price risk management program in place whereby the commodity price associated with a portion of its future production is fixed. The Company sells forward a portion of its future production by entering into a combination of fixed price physical sales contracts with customers and derivative financial contracts. The Company's policy is to enter into commodity contracts to a range of 40 – 50 percent of current production volumes.

As at March 31, 2011, the Company had the following derivative financial contracts which were recorded at fair value on the balance sheet as a current asset of $0.5 million, a current liability of $1.1 million and a long term liability of $4.1 million (December 31, 2010 – current asset of $2.1 million and long term liability of $3.5 million) with changes in fair value included in unrealized gain (loss) on financial instruments in the consolidated statement of earnings. For the three months ended March 31, 2011, the financial contracts resulted in realized gains of $0.3 million (March 31, 2010

- $0.1 million) that have been included in the consolidated statement of earnings as a realized gain on financial instruments.

As at March 31, 2011, if natural gas prices had been higher by $0.10 per mcf, with all other variables held constant, the net change in the unrealized gain (loss) on financial instruments in the consolidated statement of earnings for the three months ended would have been higher by approximately $0.4 million (March 31, 2010 – lower by $0.4 million).

Time Period	Commodity	Type and Reference	Quantity Contracted	Contract Price ($/unit)
January 2011–December 2011*	Natural Gas	Financial – AECO	2,500 GJ/d	$7.14 call
January 2011–December 2011***	Natural Gas	Financial – AECO	3,000 GJ/d	$4.00 put
January 2011–December 2012**	Crude Oil	Financial – WTI	600 bbls/d	U.S. $90.00 call
April 2011–October 2011	Natural Gas	Financial – AECO	2,000 GJ/d	$3.79 fixed
April 2011–October 2011	Natural Gas	Financial – AECO	2,000 GJ/d	$3.82 fixed
April 2011–December 2011**	Natural Gas	Financial – AECO	6,810 GJ/d	$5.69 fixed
January 2012–December 2012***	Natural Gas	Financial – AECO	3,000 GJ/d	$4.50 call

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

** 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 also has physical sales contracts. The physical sales contracts were entered into and continue to be held for the purpose of delivery of non-financial items as executory contracts and have not been recorded at fair value, except for the US dollar based contract. The foreign exchange component of the US dollar based contract is an embedded derivative which results in the entire contract being accounted for as a derivative financial instrument even though physical delivery of natural gas to the US reference point takes place. As at March 31, 2011, the Company had the following physical sales contracts.

Time Period	Commodity	Type and Reference	Quantity Contracted	Contract Price ($/unit)
January 2011–December 2011	Natural Gas	Physical – AECO	2,500 GJ/d	$3.79 fixed
January 2011–December 2011****	Natural Gas	Physical – AECO	2,500 GJ/d	$4.12 fixed
April 2011–October 2011	Natural Gas	Physical – AECO	2,000 GJ/d	$5.66 fixed
April 2011–October 2011	Natural Gas	Physical – AECO	4,000 GJ/d	$3.80 fixed
April 2011–December 2011	Natural Gas	Physical – Chicago	2,000 GJ/d	U.S. $4.52 fixed
January 2012–December 2012****	Natural Gas	Physical - AECO	2,500 GJ/d	$4.50 call

**** 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.

For the three months ended March 31, 2011, the Canadian dollar physical contracts resulted in settlement gains of $1.6 million (March 31, 2010 - $2.9 million) that have been included in crude oil and natural gas sales.

(b) Credit risk

Credit risk represents the risk of financial loss to the Company if customers or counterparties to a financial instrument fail to meet their contractual obligations and arise principally from the Company's receivables from joint interest partners, crude oil and natural gas marketers and financial intermediaries.

All of the Company's accounts receivable are with customers and joint interest partners in the oil and gas industry and are subject to normal industry credit risks. Receivables from joint interest partners are typically collected within one to three months of the joint venture bill being issued. The Company attempts to mitigate the risk related to joint interest receivables by obtaining partner pre-approval of significant capital expenditures prior to expenditure. However, partners are exposed to various crude oil and natural gas industry and market risks that could result in non-collection.

Receivables from crude oil and natural gas marketers are normally collected on the 25th day of the month following production. The Company's policy to mitigate credit risk associated with these balances is to establish marketing relationships with large purchasers. The Company historically has not experienced any collection issues with large purchasers. Concentration of credit risk is mitigated by marketing production to numerous purchasers under normal industry sale and payment terms.

The Company does not typically obtain collateral from crude oil and natural gas marketers or joint interest partners, however, the Company does have the ability to request pre-payment of certain major capital expenditures and withhold production from joint interest partners in the event of non-payment.

With respect to counterparties to financial commodity contracts, the Company partially mitigates associated credit risk by limiting transactions to counterparties with investment grade credit ratings.

The carrying amount of cash and accounts receivable represents the maximum credit exposure. As at March 31, 2011, the Company's receivables included $11.2 million of receivables from crude oil and natural gas marketers which has substantially been collected since March 31, 2011. The Company does not have an allowance for doubtful accounts as at March 31, 2011.

As at March 31, 2011 the Company's aged receivables are as follows.

	March 31, 2011
Current (less than 30 days)	**15,842**
Past due (31-90 days)	**4,160**
Past due (more than 90 days)	**1,583**
Total	**21,585**

(c) Liquidity risk

Liquidity risk is the risk that the Company will not be able to meet the obligations associated with its financial liabilities. The Company's financial liabilities arise through the cost of operations and capital program in order to maintain or increase production and develop reserves, the acquisition of crude oil and natural gas assets, financial instrument contracts and borrowings under the Company's credit facilities.

The Company generates a certain level of cash flow from operations which is used to partially fund all operating, investing and capital activities. In addition, the Company has a 364 day revolving credit facility with a syndicate of Canadian chartered banks with a one year term-out provision.

The following are the contractual maturities of financial liabilities as at March 31, 2011.

Financial liabilities	< 1 Year	1 – 2 Years	3 – 5 Years	Thereafter
Accounts payable and accrued liabilities	44,489	-	-	-
Fair value of financial instruments	1,108	4,088	-	-
Long term debt	-	104,513	-	-
Total	45,597	108,601	-	-

(d) Currency risk

Although substantially all of the Company's petroleum and natural gas sales are denominated in Canadian dollars, commodity prices are largely denominated in US dollars and as a result the prices that Canadian producers receive are influenced by the relationship between the Canadian and US dollar. The exchange rate effect cannot be quantified but generally an increase in the value of the Canadian dollar as compared to the US dollar will reduce the prices received by the Company for its crude oil and natural gas sales. The Company had no foreign exchange rate swap or related financial contracts in place as at March 31, 2011.

(e) Interest rate risk

Interest rate risk is the risk that future cash flow will fluctuate as a result of changes in market interest rates. Delphi is exposed to interest rate risk as the interest charged on its long term debt is at a floating rate and consequently changes in market interest rates will have an effect on the Company's cash flow.

Interest rate risk is partially mitigated through short term fixed rate borrowings using bankers' acceptances.
The Company has also entered into an interest rate swap transaction on long term debt through bankers' acceptances in the amount of $40.0 million, maturing on May 4, 2011. The fair value of this contract at March 31, 2011 is a loss of $16,000.
Had the interest rate charged on the Company's long term debt been one percent higher throughout the three months ended March 31, 2011, net earnings would have decreased by $0.1 million based on the average debt balance outstanding during the period, excluding the $40.0 million hedged by the interest rate swap outlined above.

6) CAPITAL MANAGEMENT

The Company's policy is to ensure a strong capital base so as to maintain investor, creditor and market confidence and to sustain future development of the business. The Company's objective in managing its capital is to ensure adequate and appropriate sources of capital are available to execute a capital investment program while maintaining a flexible overall capital structure. Maintaining a flexible capital structure is important due to the inherent risks in oil and gas operations and the volatility of commodity prices.

The Company considers share capital and net debt, being the sum of long term debt and current liabilities less current assets (excluding fair value of financial instruments), as the components of capital to be managed.

The key measure used by the Company to evaluate its capital structure is the ratio of net debt to funds from operations, defined as cash flow from operating activities before expenditures on asset retirement obligations and change in non-cash working capital from operating activities. This ratio represents the time period required to repay the Company's net debt from funds generated from operations on the assumption there are no further capital expenditures incurred and funds from operations remain constant. The measure is often calculated on a historic annual basis and on an annualized most recent quarter basis to provide a more current view of the Company's capital structure.

At March 31, 2011 net debt was $116.9 million and funds from operations was $15.1 million resulting in a net debt to funds from operations ratio of 1.9:1. This ratio may increase at certain times as a result of acquisitions or low commodity prices. The Company is focused on achieving its internal target for this ratio of approximately 1.5 times.

In order to facilitate the management of this ratio, the Company prepares annual funds from operations and capital expenditure budgets, which are updated as necessary throughout the year and are reviewed and periodically approved by Delphi's Board of Directors. The Company manages its capital structure by keeping abreast of current and forecast economic conditions and commodity prices, particularly natural gas prices and the cost of oilfield services. Additionally, the Company establishes internal processes to monitor and estimate planned capital expenditures, forecast funds from operations and current and forecast debt levels.

The Company maintains an active risk management program as an integral part of its capital management strategy to mitigate the volatility in funds from operations resulting from fluctuating commodity prices. The net debt to funds from operations ratio is the key driver in determining whether to maintain or alter the capital structure. To alter the capital structure of the Company, consideration is given to the level of credit available under current banking facilities, the proceeds on disposition of properties, the amount of the planned capital expenditure program and the offering of new common share equity if available on acceptable terms. There were no changes in the Company's approach to capital management during the period.

The Company's share capital is not subject to external restrictions, however, the Company's credit facilities do contain financial covenants that are outlined in note 10.

7) ASSETS AND LIABILITIES HELD FOR SALE

In 2009, the Company made the decision to market for disposition its non-core cash generating unit located in East Central Alberta. The cash generating unit consisted of medium quality oil and and natural gas production with very high operating costs. Due to the significant number of producing and non-producing wells and facilities on the properties, the cash generating unit was also burdened by decommissioning obligations of approximately $2.6 million.

IFRS 5 outlines the requirements for the classification, measurement and presentation of non-current assets held for sale. The assets were marketed actively at a price that was reasonable in relation to its fair value, disposition was expected within a year from the date of classification as an asset held for sale, a plan had been put together to complete the disposition and management was committed to concluding a disposition. Accordingly, the Company has classified the cash generating unit as assets and liabilities held for sale on the consolidated statement of financial position at January 1, 2010. During the second quarter of 2010, the Company concluded an agreement with an arm's length third party to dispose of the properties for cash consideration of $0.3 million, including the assumption of the decommissioning obligations.

8) EXPLORATION AND EVALUATION ASSETS

	Total
Balance as at January 1, 2010	315
Additions	2,472
Balance as at December 31, 2010	2,787
Additions	256
Balance as at March 31, 2011	**3,043**

9) PROPERTY, PLANT AND EQUIPMENT

Cost	**Crude oil and natural gas properties**	**Production equipment**	**Other assets**	**Total**
Balance as at January 1, 2010	223,100	109,266	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	306,421	130,194	621	437,236
Additions	25,831	8,201	36	34,068
Acquisitions	87	-	-	87
Change in decommissioning obligations	5	-	-	5
Balance as at March 31, 2011	**332,344**	**138,395**	**657**	**471,396**

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	(9,044)	(1,528)	(29)	(10,601)
Balance as at March 31, 2011	**(76,538)**	**(13,683)**	**(158)**	**(90,379)**
Net book value as at March 31, 2011	**255,806**	**124,712**	**499**	**381,017**
Net book value as at December 31, 2010	238,927	118,039	492	357,458
Net book value as at January 1, 2010	223,100	109,266	572	332,938

As at March 31, 2011, costs in the amount of $11.7 million (March 31, 2010 - $5.6 million) representing work in progress were excluded from the depletion calculation and estimated future development costs of $132.2 million (March 31, 2010 - $82.3 million) have been included in costs subject to depletion.

During 2010, as a result of decreasing natural gas prices, the Company recognized a $35.5 million impairment relating to several CGU's outside of the Company's focus area in the Deep Basin which predominantly produce natural gas only. At March 31, 2010, an impairment loss of $5.0 million was recognized and at September 30, 2010 an additional impairment loss of $30.5 million was taken and recognized as additional depletion and depreciation expense. 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.

10) LONG TERM DEBT

Long term debt is comprised of the following:

	March 31, 2011	December 31, 2010	January 1, 2010
Prime-based loans	**25,000**	25,000	1,100
Bankers' acceptances	**79,513**	80,000	80,000
Total	**104,513**	105,000	81,100

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 or US base rate 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 funds from operations 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.

The bankers' acceptances outstanding at March 31, 2011 have terms ranging from 88 to 182 days and a weighted average effective interest rate of 4.24 percent over the term.

Under the terms of the credit facility, the Company covenants that it will maintain a working capital ratio of at least one to one. For the purpose of this ratio, the undrawn portion of the credit facility is added to current assets in the working capital calculation. The credit facility is secured by a $200.0 million demand floating charge debenture and a general security agreement over all assets of the Company.

11) DECOMMISSIONING OBLIGATIONS

The Company's decommissioning obligations result from working interests in crude oil and natural gas assets including well sites, gathering systems and processing facilities. The total decommissioning obligation is estimated based on the Company's net ownership interest in all wells and facilities, estimated costs to reclaim and abandon the wells and facilities and the estimated timing of the costs to be incurred in future years. The Company has estimated the net present value of the decommissioning obligations to be $17.4 million as at March 31, 2011 (December 31, 2010 - $17.2 million) based on an undiscounted total future liability of $23.3 million (December 31, 2010 - $22.7 million). These payments are expected to be made over the next 20 years with the majority of the costs to be incurred between 2017 and 2023. A risk-free rate of 3.4 percent (December 31, 2010 – 3.1 percent) and an inflation rate of 2.5 percent were used to calculate the estimated fair value of the decommissioning obligations.

A reconciliation of the decommissioning obligations is provided below.

	Three Months Ended March 31, 2011	Year Ended December 31, 2010
Balance, beginning of period	**17,232**	15,496
Liabilities incurred	**366**	862
Liabilities disposed	**-**	(79)
Liabilities settled	**-**	(265)
Accretion expense	**141**	520
Change in estimate	**(361)**	698
Balance, end of period	**17,378**	17,232

12) SHARE CAPITAL

At March 31, 2011 and 2010, 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

	March 31, 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	**1,096**	**1,279**	659	775
Allocated from contributed surplus	**-**	**673**	-	418
Share issue costs	**-**	**(14)**	-	(1,966)
Future tax effect of share issue costs	**-**	**-**	-	523
Balance, end of period	**117,121**	**246,480**	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 has been recorded as a long term liability on the consolidated statement of financial position. The liability will be reversed as qualified expenditures are incurred. 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.

On June 3, 2010, the Company issued 11.0 million common shares at a price of $2.75 per share for gross proceeds of $30.3 million.

(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 on September 1, 2009 or later 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. 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 March 31, 2011 there were 6.7 million options to purchase shares outstanding.

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

	March 31, 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	**90**	**2.15**	1,074	2.64
Forfeited	**(95)**	**2.36**	(67)	1.50
Exercised	**(1,096)**	**1.17**	(659)	1.18
Balance, end of period	**6,675**	**1.66**	7,776	1.59
Exercisable, end of period	**5,674**	**1.56**	6,116	1.58

The following table summarizes information about the stock options outstanding and exercisable at March 31, 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	**1,298**	**0.65**	**2.92**	**1,298**	**0.65**
$0.98 - $1.54	**405**	**1.22**	**3.05**	**160**	**1.28**
$1.55 - $1.72	**3,295**	**1.68**	**1.70**	**3,270**	**1.68**
$1.73 - $2.15	**605**	**1.90**	**2.60**	**395**	**1.78**
$2.16 - $3.34	**1,072**	**2.82**	**3.69**	**551**	**2.92**
Total	**6,675**	**1.66**	**2.42**	**5,674**	**1.56**

The weighted average share price at the date of exercise for stock options exercised in 2011 was $2.32 (2010 - $2.64). The Company accounts for its share-based compensation using the fair value method for all stock options. For the three months ended March 31, 2011, Delphi recorded non-cash compensation expense of $0.2 million (March 31, 2010 - $0.1 million).

During the three months ended March 31, 2011, the Company granted 0.1 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 $1.21 per option (March 31, 2010 - $1.54 per option). The assumptions used in the Black-Scholes model to determine fair value were as follows.

For the three months ended March 31	**2011**	2010
Risk-free interest rate (%)	**2.7**	2.7
Expected life (years)	**5.0**	5.0
Forfeiture rate (%)	**4.7**	3.8
Expected volatility (%)	**64.6**	65.8

(d) Net earnings (loss) per share

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

For the three months ended March 31	**2011**	**2010**
Weighted average common shares - basic	**113,465**	101,247
Stock options	**2,238**	2,987
Weighted average common shares - diluted	**115,703**	104,234

13) FINANCE COSTS

For the three months ended March 31	**2011**	2010
Interest expense	**1,380**	1,342
Accretion expense	**141**	138
Total	**1,521**	1,480

14) SUPPLEMENTAL CASH FLOW INFORMATION

Changes in non-cash working capital are comprised of the following:

For the three months ended March 31	**2011**	2010
Source/(use) of cash		
Accounts receivable	**(3,688)**	(9,818)
Prepaid expenses and deposits	**(501)**	821
Accounts payable and accrued liabilities	**16,073**	25,667
Total change in non-cash working capital	**11,884**	16,670
Relating to:		
Operating activities	**(3,506)**	(4,028)
Investing activities	**15,390**	20,698
	11,884	16,670

15) FIRST TIME ADOPTION OF INTERNATIONAL FINANCIAL REPORTING STANDARDS

These are the Company's first 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 in Note 3 have been applied in preparing the interim consolidated financial statements for the first three months ended March 31, 2011, the comparative information for the three months ended March 31, 2010, the statement of financial position for the year ended December 31, 2010 and the opening IFRS statement of financial position as at January 1, 2010..

An explanation of how the transition from previous GAAP to IFRS has affected the Company's financial position and financial performance 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 GAAP. The Company has elected to measure its properties at the amount determined under previous 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 Opening Consolidated Statement of Financial Position
As at January 1, 2010

(thousands of dollars)	Notes	Previous GAAP	Effect of Transition to IFRS	IFRS
Assets				
Current assets				
Accounts receivable		15,630	-	15,630
Prepaid expenses and deposits		6,004	-	6,004
Assets held for sale	**a)**	-	2,804	2,804
Fair value of financial instruments		-	104	104
Deferred income taxes	**i)**	112	(112)	-
		21,746	2,796	24,542
Exploration and evaluation assets	**b)**	-	315	315
Property, plant and equipment	**c)**	339,952	(7,014)	332,938
Total assets		**361,698**	**(3,903)**	**357,795**
Liabilities				
Current liabilities				
Outstanding cheques		139		139
Accounts payable and accrued liabilities		32,933		32,933
Liabilities held for sale	**a)**	-	2,554	2,554
Fair value of financial instruments		381	(381)	-
		33,453	2,173	35,626
Other liability	**j)**	-	960	960
Long term debt		81,100	-	81,100
Decommissioning obligations	**e)**	11,818	3,678	15,496
Fair value of financial instruments		-	485	485
Deferred income taxes	**i)**	23,917	(2,773)	21,144
		150,288	4,523	154,811
Shareholders' equity				
Share capital	**j)**	200,055	6,327	206,382
Contributed surplus	**f)**	11,048	(21)	11,027
Deficit	**k)**	307	(14,732)	(14,425)
Total shareholders' equity		211,410	(8,426)	202,984
Total liabilities and shareholders' equity		**361,698**	**(3,903)**	**357,795**

IFRS Consolidated Statement of Financial Position
As at March 31, 2010

(thousands of dollars)	Notes	Previous GAAP	Effect of Transition to IFRS	IFRS
Assets				
Current assets				
Accounts receivable		25,448	-	25,448
Prepaid expenses and deposits		5,183	-	5,183
Assets held for sale	**a)**	-	2,804	2,804
Fair value of financial instruments		3,056	91	3,147
		33,687	2,895	36,582
Exploration and evaluation assets	**b)**	-	2,611	2,611
Property, plant and equipment	**c)**	362,757	(10,799)	351,958
Total assets		**396,444**	**(5,293)**	**391,151**
Liabilities				
Current liabilities				
Outstanding cheques		5,270	-	5,270
Accounts payable and accrued liabilities		58,600	-	58,600
Liabilities held for sale	**a)**	-	2,554	2,554
Deferred income taxes	**i)**	889	(889)	-
		64,759	1,665	66,424
Other liability	**j)**	-	266	266
Long term debt		80,000	-	80,000
Decommissioning obligations	**e)**	12,181	3,807	15,988
Fair value of financial instruments		-	91	91
Deferred income taxes	**i)**	25,895	(2,645)	23,250
		182,835	3,184	186,019
Shareholders' equity				
Share capital	**j)**	198,955	7,942	206,897
Contributed surplus	**f)**	11,087	(40)	11,047
Deficit	**k)**	3,567	(16,379)	(12,812)
Total shareholders' equity		213,609	(8,477)	205,132
Total liabilities and shareholders' equity		**396,444**	**(5,293)**	**391,151**

IFRS Consolidated Statement of Financial Position
As at December 31, 2010

(thousands of dollars)	Notes	Previous GAAP	Effect of Transition to IFRS	IFRS
Assets				
Current assets				
Cash and cash equivalents		4,039	-	4,039
Accounts receivable		17,897	-	17,897
Prepaid expenses and deposits		3,426	-	3,426
Fair value of financial instruments		2,080	-	2,080
		27,442	-	27,442
Exploration and evaluation assets	**b)**	-	2,787	2,787
Property, plant and equipment	**c)**	384,887	(27,429)	357,458
Total assets		**412,329**	**(24,642)**	**387,687**
Liabilities				
Current liabilities				
Accounts payable and accrued liabilities		28,416	-	28,416
Deferred income taxes	**i)**	551	(551)	-
		28,967	(551)	28,416
Long term debt		105,000	-	105,000
Decommissioning obligations	**e)**	10,984	6,248	17,232
Fair value of financial instruments		3,527	-	3,527
Deferred income taxes	**i)**	23,860	(7,308)	16,552
		172,338	(1,611)	170,727
Shareholders' equity				
Share capital	**j)**	228,440	7,942	236,382
Contributed surplus	**f)**	12,088	(101)	11,987
Deficit	**k)**	(537)	(30,872)	(31,409)
Total shareholders' equity		239,991	(23,031)	216,960
Total liabilities and shareholders' equity		**412,329**	**(24,642)**	**387,687**

IFRS Consolidated Statement of Earnings
Three Months Ended March 31, 2010

(thousands of dollars)	Notes	Previous GAAP	Effect of Transition to IFRS	IFRS
Revenue				
Petroleum and natural gas sales		29,456	-	29,456
Royalties		(3,814)	-	(3,814)
		25,642	-	25,642
Realized gain on financial instruments		63	-	63
Unrealized gain on financial instruments		3,437	-	3,437
		29,142	-	29,142
Expenses				
Operating	**g)**	5,991	(6)	5,985
Transportation		2,196	-	2,196
Exploration and evaluation	**c)**	-	298	298
General and administrative	**g)**	1,019	114	1,133
Share-based compensation	**f)**	105	(12)	93
Depletion and depreciation	**d)**	13,902	1,066	14,968
		23,213	1,460	24,673
Finance costs	**h)**	(1,342)	(138)	(1,480)
Earnings before taxes		4,587	(1,598)	2,989
Taxes				
Deferred income taxes	**i)**	1,327	49	1,376
		1,327	49	1,376
Net earnings and comprehensive earnings		3,260	(1,647)	1,613

IFRS Consolidated Statement of Earnings
Year Ended December 31, 2010

(thousandsof dollars)	Notes	Previous GAAP	Effect of Transition to IFRS	IFRS
Revenue				
Petroleum and natural gas sales		113,772	-	113,772
Royalties		(14,420)	-	(14,420)
		99,352	-	99,352
Realized gain on financial instruments		3,427	-	3,427
Unrealized loss on financial instruments		(1,066)	-	(1,066)
		101,713	-	101,713
Expenses				
Operating	**g)**	22,013	(58)	21,955
Transportation		8,908	-	8,908
Exploration and evaluation	**c)**	-	195	195
General and administrative	**g)**	5,531	898	6,429
Share-based compensation	**f)**	990	37	1,027
Depletion and depreciation	**d)**	60,687	19,091	79,778
		98,129	20,163	118,292
Finance costs	**h)**	(5,075)	(520)	(5,595)
Earnings before taxes		(1,491)	(20,683)	(22,174)
Taxes				
Deferred income taxes	**i)**	(647)	(4,542)	(5,189)
		(647)	(4,542)	(5,189)
Net loss and comprehensive loss		(844)	(16,141)	(16,985)

Notes to reconciliations:

a) Assets held for sale – Upon transition to IFRS, Delphi recorded an impairment on its East Central Alberta ("ECAB") 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 assets and liabilities were 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 (thousands)	**As at Jan. 1 2010**	**As at Mar. 31 2010**	**As at Dec. 31 2010**
Reclass of assets to held for sale	2,804	2,804	-
Reclass of liabilities to held for sale	(2,554)	(2,554)	-
	250	250	-

b) Exploration and evaluation ("E&E") assets – Upon transition to IFRS, Delphi recorded all E&E expenditures that were included in property, plant and equipment ("PP&E") on the consolidated statement of financial position. This consisted of the carrying amount for Delphi's undeveloped land that related directly to exploration properties. Management identified and reclassified the following amounts from PP&E to E&E.

Consolidated statement of financial position (thousands)	**As at Jan. 1 2010**	**As at Mar. 31 2010**	**As at Dec. 31 2010**
Additions to E&E	315	2,413	2,032
Capitalization of directly related overhead	-	171	692
Capitalization of share-based compensation	-	27	63
	315	2,611	2,787

c) Property, plant and equipment– Delphi's PP&E assets were allocated to CGU's whereas under previous 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 financial position (thousands)	**As at Jan. 1 2010**	**As at Mar. 31 2010**	**As at Dec. 31 2010**
Additions to E&E	(315)	(2,413)	(2,032)
Impairment of ECAB CGU	(3,895)	(3,895)	(3,895)
ECAB CGU recorded as asset held for sale	(2,804)	(2,804)	(704)
Expensing of dry hole costs	-	(298)	(195)
Decrease in depletion and depreciation	-	3,688	15,398
Change in decommissioning obligations	-	180	456
Capitalization of directly related overhead	-	(280)	(1,532)
Capitalization of share-based compensation	-	(34)	(180)
Rate change in decommissioning obligations	-	57	755
Impairment losses	-	(5,000)	(35,500)
	(7,014)	(10,799)	(27,429)

Consolidated statement of earnings (thousands)	**Three Months Ended Mar. 31, 2010**	**Year Ended Dec. 31, 2010**
Expensing of dry hole costs	298	195

d) 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 (thousands)	Three Months Ended Mar. 31, 2010	Year Ended Dec. 31, 2010
Decrease in depletion and depreciation	(3,688)	(15,398)
Reclassification of accretion expense	(246)	(1,011)
Impairment losses	5,000	35,500
Increase in depletion and depreciation	1,066	19,091

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 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 produce natural gas. At March 31, 2010, an impairment loss of $5.0 million was recognized and at September 30, 2010 an additional impairment loss of $30.5 million was taken and recognized as additional depletion and depreciation expense.

e) Decommissioning obligations – 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.

Consolidated statement of financial position (thousands)	As at Jan. 1, 2010	As at Mar. 31, 2010	As at Dec. 31, 2010
Revaluation of decommissioning obligations	6,232	6,232	6,232
Change in decommissioning obligations	-	129	720
Reclassification of ECAB decommissioning obligations to liabilities held for sale	(2,554)	(2,554)	(704)
	3,678	3,807	6,248

f) Share-based compensation – 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. Delphi recorded a decrease of $21,000 to contributed surplus upon transition to IFRS.

Consolidated statement of financial position (thousands)	As at Jan. 1, 2010	As at Mar. 31, 2010	As at Dec. 31, 2010
Change due to forfeiture rate	(21)	(40)	(101)

Consolidated statement of earnings (thousands)	Three Months Ended Mar. 31, 2010	Year Ended Dec. 31, 2010
Change to share-based compensation	(19)	(80)
Share-based compensation capitalized to PP&E	34	180
Share-based compensation capitalized to E&E	(27)	(63)
	(12)	37

g) Capitalized directly related overhead

Consolidated statement of earnings (thousands)	**Three Months Ended Mar. 31, 2010**	**Year Ended Dec. 31, 2010**
Decrease in capitalized directly related overhead	108	840
Transfer from operating expense to general and administration	6	58
	114	898

h) 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 (thousands)	**Three Months Ended Mar. 31, 2010**	**Year Ended Dec. 31, 2010**
Accretion expense	(138)	(520)

i) 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 decrease in deferred tax liability is primarily due to the adjustments to the opening balances of property, plant and equipment and decommissioning liabilities on transition to IFRS.

Consolidated statement of financial position (thousands)	**As at Jan. 1, 2010**	**As at Mar. 31, 2010**	**As at Dec. 31, 2010**
Deferred income tax related to transition to IFRS	(2,773)	(2,645)	(7,308)

Consolidated statement of earnings (thousands)	**Three Months Ended Mar. 31, 2010**	**Year Ended Dec. 31, 2010**
Deferred income tax related to transition to IFRS	49	(4,542)

j) 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 share capital.

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 share issue costs under IFRS.

Consolidated statement of financial position (thousands)	**As at Jan. 1, 2010**	**As at Mar. 31, 2010**	**As at Dec. 31, 2010**
Flow-through adjustment	7,409	7,409	7,409
Flow-through issuance in 2009	(960)	655	655
Share issue cost adjustment	(122)	(122)	(122)
	6,327	7,942	7,942

k) Retained earnings (deficit)

Consolidated statement of financial position (thousands)	**As at Jan. 1, 2010**	**As at Mar. 31, 2010**	**As at Dec. 31, 2010**
Decommissioning obligations	(6,232)	(6,182)	(6,496)
Share-based compensation	21	33	(16)
Flow-through adjustment	(7,409)	(8,064)	(8,064)
Flow-through premium	-	(266)	-
ECAB impairment	(3,895)	(3,895)	(3,895)
Share issue cost adjustment	122	122	122
Deferred income tax	2,661	3,534	7,859
Capitalized directly related overhead	-	(108)	(840)
Depletion and depreciation	-	3,688	15,398
Rate change in decommissioning obligations	-	57	755
Expensing of dry hole costs	-	(298)	(195)
Impairment losses	-	(5,000)	(35,500)
	(14,732)	(16,379)	(30,872)

DIRECTORS

David J. Reid
President and Chief Executive Officer
Delphi Energy Corp.

Tony Angelidis
Senior Vice President Exploration
Delphi Energy Corp.

Harry S. Campbell, Q.C. (3)
Partner
Burnet, Duckworth & Palmer LLP

Robert A. Lehodey, Q.C. (2) (3)
Partner
Osler, Hoskin & Harcourt LLP

Stephen Mulherin (1)
Partner
Polar Capital Corporation

Andrew E. Osis (1)
Chief Executive Officer and Director
Poynt Corporation

David Sandmeyer (2)
Director
Freehold Royalty Trust

Lamont C. Tolley (1) (2)
Independent Businessman

(1) Member of the Audit Committee
(2) Member of the Reserves Committee
(3) Member of the Corporate Governance and Compensation Committee

OFFICERS

David J. Reid
President and Chief Executive Officer

Tony Angelidis
Senior Vice President Exploration

Hugo H. Batteke
Vice President Operations

Michael K. Galvin
Vice President Land

Rod A. Hume
Vice President Engineering

Michael S. Kaluza
Chief Operating Officer

Brian P. Kohlhammer
Vice President Finance and Chief Financial Officer

CORPORATE OFFICE

300, 500 – 4th Avenue S.W.
Calgary, Alberta T2P 2V6
Telephone: (403) 265-6171
Facsimile: (403) 265-6207
Email: info@delphienergy.ca
Website: www.delphienergy.ca

BANKERS

National Bank of Canada
The Bank of Nova Scotia
Alberta Treasury Branches

AUDITORS

KPMG LLP

INDEPENDENT ENGINEERS

GLJ Petroleum Consultants Ltd.

LEGAL COUNSEL

Osler, Hoskin & Harcourt LLP

STOCK EXCHANGE LISTING

Toronto Stock Exchange – DEE

TRANSFER AGENT

Olympia Trust Company

ABBREVIATIONS

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

Delphi Energy Corp.
300, 500 – 4 Avenue S.W.
Calgary, Alberta
T2P 2V6

Telephone: (403) 265-6171
Facsimile: (403) 265-6207
Website: www.delphienergy.ca
Email: info@delphienergy.ca

WWW.DELPHIENERGY.CA