Q3

For The Nine Months Ended

September 30, 2014

DELPHI ENERGY CORP.

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Third Quarter 2014 Highlights

- Average production of 9,461 barrels of oil equivalent per day ("boe/d") in the third quarter of 2014, an increase of eight percent over the comparative quarter in 2013 despite downtime in Montney and Wapiti. This downtime resulted in a reduction of volumes for the third quarter of approximately 1,700 boe/d;

- Improved cash netbacks per barrels of oil equivalent ("boe") in the third quarter of 2014 by 33 percent to $16.34 per boe over the comparative quarter of 2013, resulting in funds from operations of $14.2 million, a 43 percent increase over the third quarter of 2013;

- Increased average field condensate production by 74 percent to 1,227 barrels per day ("bbls/d") in comparison to the third quarter of 2013;

- Increased average Montney production from 3,512 boe/d in the third quarter of 2013 to 5,502 boe/d in the third quarter of 2014, an increase of 57 percent despite downtime in August 2014. The Bigstone Montney project contributed 58 percent of the Company's production during the third quarter of 2014 compared to 40 percent during the comparative quarter of 2013;

- Montney liquids yield was 93 barrels per million cubic feet ("bbls/mmcf") in the third quarter of 2014 with field and plant condensate representing 71 percent of the liquids yield and the balance of the liquids yield split between butane at 15 percent and propane at 14 percent;

- Acquired eight gross (3.5 net) sections of Montney rights at East Bigstone for a purchase price of $8.8 million after closing adjustments;

- Closed the sale of certain interests from its Hythe property for net proceeds of $16.0 million after closing adjustments; and

- Successfully drilled, completed and tied-in two gross (1.75 net) Montney wells as part of the Company's capital program. One well was brought on production late in the quarter and the other well was brought on production in the fourth quarter.

Operational Highlights

	Three Months Ended September 30			Nine Months Ended September 30		
Production	**2014**	2013	% Change	**2014**	2013	% Change
Field condensate (bbls/d)	**1,227**	705	74	**1,348**	601	124
Natural gas liquids (bbls/d)	**1,356**	1,294	5	**1,551**	1,200	29
Crude oil (bbls/d)	**169**	330	(49)	**210**	320	(34)
Total crude oil and natural gas liquids	**2,752**	2,329	18	**3,109**	2,121	47
Natural gas (mcf/d)	**40,251**	38,807	4	**41,646**	35,209	18
Total (boe/d)	**9,461**	8,797	8	**10,050**	7,989	26

Financial Highlights ($ thousands except per unit amounts)

	Three Months Ended September 30			Nine Months Ended September 30		
	2014	2013	% Change	**2014**	2013	% Change
Crude oil and natural gas sales	**35,117**	25,666	37	**128,336**	70,970	81
Realized sales price per boe	**38.69**	32.94	17	**42.82**	32.89	30
Funds from operations	**14,221**	9,972	43	**49,290**	27,763	78
Per boe	**16.34**	12.32	33	**17.96**	12.73	41
Per share – Basic	**0.09**	0.07	29	**0.32**	0.18	78
Per share – Diluted	**0.09**	0.06	50	**0.31**	0.18	72
Net earnings	**12,163**	1,208	907	**18,325**	4,473	310
Per boe	**13.97**	1.49	838	**6.68**	2.05	226
Per share – Basic	**0.08**	0.01	700	**0.12**	0.03	300
Per share – Diluted	**0.08**	0.01	700	**0.11**	0.03	267
Capital invested	**29,350**	13,015	126	**83,999**	44,332	89
Disposition of properties	**(15,964)**	(42)	37,910	**(15,964)**	(3,319)	381
Net capital invested	**13,386**	12,973	3	**68,035**	41,013	66
Acquisition of undeveloped properties	**8,800**	-	-	**8,800**	13,664	(36)
Total capital invested	**22,186**	12,973	71	**76,835**	54,677	41

	September 30, 2014	December 31, 2013	% Change
Net debt [1]	**165,228**	138,340	19
Total assets	**518,050**	451,680	15
Shares outstanding (000's)			
Basic	**155,441**	153,254	1
Diluted	**168,208**	166,106	1

[1] Defined as the sum of long term and subordinated debt plus (minus) the working capital deficit (surplus) excluding the current portion of the fair value of the financial instruments.

MESSAGE TO SHAREHOLDERS

Delphi continues to focus its capital program for 2014 on its Montney development at Bigstone, increasing the Company's cash generating capability through the growth of its liquids-rich production, towards a self-funded drilling program.

Revenue generated during the third quarter of 2014 was $35.1 million, a 37 percent increase over the comparative quarter of 2013 which had revenue of $25.7 million. In the third quarter of 2014, sales of crude oil, field condensate and natural gas liquids ("NGL") production represented 53 percent of revenue and sales of natural gas production represented 47 percent of revenue. For the nine months ended September 30, 2014, revenue was $128.3 million, an 81 percent increase over the comparative period of 2013 which had revenue of $71.0 million. For the nine months ended September 30, 2014, sales of crude oil, field condensate and natural gas liquids production represented 52 percent of revenue and sales of natural gas production represented 48 percent of revenue.

Funds from operations in the third quarter of 2014 were $14.2 million or $0.09 per basic and diluted share compared to $10.0 million or $0.07 per basic share and $0.06 per diluted share in the comparative quarter of 2013. The increase in funds from operations is primarily due to an increase in field condensate, natural gas liquids and natural gas production and an improvement in the price received for natural gas and NGLs in the third quarter of 2014. For the nine months ended September 30, 2014, funds from operations were $49.3 million, already exceeding funds from operations of $39.1 million for all of 2013.

Production volumes for the three months ended September 30, 2014 averaged 9,461 boe/d, an increase of eight percent over the comparative quarter in 2013. During the third quarter of 2014, the Company's Montney and Wapiti volumes were curtailed due to third party processing and transportation constraints, affecting third quarter production volumes by approximately 1,700 boe/d. Production from the Montney project at Bigstone averaged 5,502 boe/d in the third quarter of 2014, up 57 percent from 3,512 boe/d in the third quarter of 2013. With third party curtailments remedied by the end of August, average total production for the two months of September and October has been approximately 11,500 boe/d based on field production estimates.

The Company's production portfolio for the third quarter of 2014 was weighted 13 percent to field condensate, 14 percent to natural gas liquids, two percent to crude oil and 71 percent to natural gas. This compares to a production portfolio for the comparative quarter of 2013 weighted eight percent to field condensate, 15 percent to natural gas liquids, three percent to crude oil and 74 percent to natural gas. For the third quarter of 2014, Delphi's field condensate production increased 74 percent to 1,227 bbls/d and NGL production increased five percent to 1,356 bbls/d compared to the third quarter of 2013. Plant and field condensate production increased from 1,045 bbls/d to 1,621 bbls/d over this same comparative period.

The liquids-rich nature of the Montney production continues to strengthen the Company's cash generating capability, as evidenced by the significant growth in revenue in 2014 over the comparative periods of 2013. Montney field operating netbacks (excluding risk management contracts) averaged $26.86 per boe during the third quarter of 2014 and $31.96 per boe for the first nine months of 2014. Production from the Montney for the nine months ended September 30, 2014 represented 58 percent of total production while generating 71 percent of field cash operating income (excluding risk management contracts).

In the third quarter of 2014, Delphi invested $29.4 million of capital expenditures and $8.8 million on the acquisition of properties which were partially funded by proceeds on disposition of $16.0 million. During the third quarter of 2014, Delphi directed 61 percent of its capital invested toward drilling, completion and equipping of two gross (1.8 net) wells and 34 percent on facility expenditures. One well was brought on production late in the quarter and the other well was brought on during the fourth quarter. During the third quarter of 2014, Delphi commenced and completed the construction of its nine million cubic feet per day ("mmcf/d") South Bigstone compression/dehydration facility and gathering system to handle production in the area. The Company has also completed pipeline connections to deliver its Montney natural gas and natural gas liquids from its East and South Bigstone facilities to the SemCams K3 processing facility.

Late in the third quarter of 2014, the Company closed the sale of certain interests from its Hythe property for net proceeds of $16.0 million after closing adjustments. The disposed assets were producing approximately 430 boe/d (55 percent natural gas) and included 23.3 gross (17.7 net) sections of primarily shallow Cretaceous rights. The Company also closed the acquisition of eight gross (3.5 net) sections of Montney rights directly offsetting Delphi's current Montney production and recent drilling activity at East Bigstone for a purchase price of $8.8 million. The acquisition was funded by the Hythe property disposition.

As at September 30, 2014, the Company's net debt was $165.2 million. On an annualized, third quarter funds from operations basis, Delphi's net debt to funds from operations ratio was 2.9:1. During the third quarter of 2014, Montney and Wapiti volumes were curtailed due to third party constraints, affecting the third quarter production volumes by approximately 1,700 boe/d and funds from operations by approximately $4.0 million. Including the $4.0 million of funds from operations from the curtailed production, as at September 30, 2014, the net debt to funds from operations ratio would have been 2.3:1.

Operations

Bigstone Montney Program

The production profile of the Bigstone Montney wells, with lower initial declines and greater condensate yields resulting in materially greater present value of the reserves and significantly reduced payout times, continues to have a favourable impact on the Company's cash generating capability and underlying asset value. Delphi has achieved payout on three of the ten Bigstone Montney wells within six to 14 months of their on-production dates, with three more expected to achieve payout by the end of 2014.

Delphi has successfully completed its seventh Montney horizontal well of 2014 at 13-23-60-23 W5M (“13-23”) in East Bigstone. The 13-23 well (100 percent working interest) was drilled to a total depth of 4,995 metres with a horizontal lateral length of 2,161 metres and stimulated with a 30 stage slickwater hybrid completion. The well is currently being equipped to produce through the Company’s 100 percent owned compression and dehydration facility. 13-23 is the first well where Delphi has implemented a significant change to its fracture stimulation design with the objective of further enhancing the economics of the Montney program at Bigstone. Additional design enhancements are expected to be evaluated throughout the 2015 drilling program.

During the third quarter, Delphi increased its Montney land position to 138 gross sections. The Company continues to pursue additional consolidation opportunities in the Bigstone area leveraging off of its control of critical infrastructure and advanced understanding of the Montney play in the area.

Delphi anticipates the expansion of the 100 percent owned Bigstone dehydration and compression facility to 55 mmcf/d will be completed during the first quarter of 2015, giving the Company capacity to process the forecast Montney production growth into 2016.

2015 Guidance

The 2015 capital program contemplates drilling and completing eight extended-reach Montney horizontal wells with a capital program funded entirely from funds from operations, resulting in a targeted 18 percent growth in annual production compared to 2014. The continued growth in volumes of the higher netback Montney production is expected to result in approximately 20 percent growth in funds from operations compared to 2014.

	2014 Guidance	2015 Guidance	% Change
Average Annual Production (boe/d)	10,300 - 10,500	12,000 - 12,500	18%
Exit Production Rate (boe/d)	11,500 - 12,000	12,750 – 13,250	11%
AECO Natural Gas Price (Cdn $ per mcf)	$4.50	$3.80	(16%)
WTI Oil Price (US $ per bbl)	$98.62	$95.00	(4%)
Net Capital Program ($ million)	$100.0 - $105.0	$77.0 - $82.0	(22%)
Funds from Operations ($ million)	$64.0 - $69.0	$77.0 - $82.0	20%
Net Debt at December 31 ($ million)	$170.0 - $175.0	$170.0 - $175.0	-
Net Debt / Q4 FFO (Annualized)	2.3	1.9	(17%)

2014 guidance has also been updated to reflect slightly higher net capital and an expectation of achieving the upper end of the 2014 annual production guidance. Capital expenditures for 2014 have been updated to reflect an early start to the 2015 drilling program and the acquisition of facility equipment to be installed in 2015 as part of a planned expansion of processing capacity at Bigstone. The fourth quarter of 2014 is forecast to average approximately 11,500 boe/d, representing a 28 percent increase over the comparative quarter of 2013 of 8,988 boe/d. Given the strong Montney production performance detailed above, the Company remains on track to meet its 2014 exit production forecast of 11,500 to 12,000 boe/d.

Delphi continues to maintain a strong commodity price risk management program. For 2015, Delphi has approximately 50 percent of its current natural gas production contracted at Cdn $3.73 per mcf with 500 bbls/d of its liquids production protected with a WTI Cdn dollar put option at a net floor price of Cdn $95.00 per barrel. As a result of the commodity price risk management program, the cash flow sensitivity to WTI pricing of US $80.00 per barrel and a Cdn/US foreign exchange rate of 1.13 is estimated to be approximately $8.0 to $9.0 million.

Outlook

The Company continues to realize gains in spud to spud cycle times of its horizontal Montney drilling program at Bigstone that resulted in an expanded 2014 drilling program. Delphi is currently drilling the final well of its 2014 accelerated drilling program and is expected to commence the first of its 2015 eight well program in December 2014.

Delphi remains focused on achieving top decile capital efficiencies at the fully-funded proved producing reserve level of the business. Simply, the focus is on turning one dollar spent into two or more dollars of proved producing reserve value within the context of the current commodity price environment.

The success of the Bigstone Montney program since implementing the new completion technique in early 2013 is demonstrated by an eleven-fold increase in Montney production to approximately 8,000 boe/d with an annual run-rate cash flow of approximately $70 million. Over that time period, the Company has spent approximately $140 million and generated cash operating income of approximately $70 million, for a current net capital investment of $70 million. The 2015 capital program is forecast to be funded entirely out of funds from operations.

The Company continues to successfully execute on its five year growth plan with production at record levels and remains on track to deploy a second drilling rig into Bigstone in 2016.

On behalf of the Board of Directors and all the employees of Delphi, we would like to thank our shareholders for their continued support.

On behalf of the Board,

David Reid

David Reid,
President and Chief Executive Officer
November 10, 2014

MANAGEMENT'S DISCUSSION AND ANALYSIS

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

Management's discussion and analysis ("MD&A") has been prepared by management and reviewed and approved by the Board of Directors of Delphi Energy Corp. ("Delphi" or "the Company"). The discussion and analysis is a review of the financial position and results of operations of the Company. Its focus is primarily a comparison of the financial performance for the three and nine months ended September 30, 2014 and 2013 and should be read in conjunction with the unaudited condensed consolidated interim financial statements and accompanying notes for the three and nine months ended September 30, 2014 and the audited consolidated financial statements of the Company for the years ended December 31, 2013 and 2012 and the related MD&A. The unaudited condensed consolidated interim financial statements have been prepared in accordance with International Accounting Standard ("IAS") 34, Interim Financial Reporting. The reporting currency is the Canadian dollar. The discussion and analysis has been prepared as of November 10, 2014.

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.

Management uses certain measures that are not recognized under IFRS to help evaluate the performance of the Company. The following are terms and definitions contained within this MD&A that are not recognized measures under IFRS:

Funds from operations - cash flow from operating activities before accretion on long term and subordinated debt, decommissioning expenditures and changes in non-cash working capital from operating activities. 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. 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 (loss) or other measures of financial performance calculated in accordance with IFRS.

Funds from operations per share - funds from operations divided by the number of common shares outstanding calculated using weighted average shares outstanding consistent with the calculation of earnings (loss) per share.

Adjusted working capital ratio – current assets include the undrawn portion of the senior credit facility and exclude the current portion of the fair value of financial instruments. Current liabilities exclude the current portion of long term debt and subordinated debt and the current portion of the fair value of financial instruments. This ratio is used to calculate the Company's compliance with its working capital ratio covenant.

Net debt to equity ratio - net debt is defined as long term debt and subordinated debt plus (minus) the working capital deficit (surplus) excluding the current portion of the fair value of financial instruments. Equity is equivalent to shareholders' equity. This ratio is used to calculate the Company's compliance with its net debt to equity ratio covenant.

Net debt to funds from operations ratio - net debt is defined as long term debt and subordinated debt plus (minus) the working capital deficit (surplus) excluding the current portion of the fair value of financial instruments. Funds from operations is defined as cash flow from operating activities before accretion of long term and subordinated debt, decommissioning expenditures and changes in non-cash working capital from operating activities. Delphi's most recently completed quarter's funds from operations is annualized (multiplied by four) for the calculation of this ratio. This ratio is used to calculate the Company's compliance with its net debt to funds from operations ratio covenant.

Total debt – the sum of long term debt and subordinated debt. This amount is used in management's calculation of net debt.

Net debt – the sum of total debt plus (minus) the working capital deficit (surplus) excluding the current portion of the fair value of the financial instruments. Net debt is used by management to monitor the remaining availability under its credit facilities.

Management considers netbacks as an important measure of the cash generating capability of the produced volumes. Netbacks are generally discussed and presented on a per boe basis.

Operating netbacks – crude oil and natural gas sales plus realized gains (losses) on financial instruments less royalties, operating and transportation costs. Management considers operating netbacks per boe an important measure of profitability relative to current commodity prices and costs of production.

Cash netbacks - operating netbacks less interest on total debt, general and administrative costs and cash costs related to the Company's restricted share units. Management considers cash netbacks per boe an important measure as it demonstrates the cash realized on each unit of production to be reinvested in future capital investment or repay debt.

DELPHI'S OPERATIONS

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

Delphi 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, from which in excess of 90 percent of the Company's production is obtained. The Company has three primary core areas in the Deep Basin located at Bigstone, Hythe and Wapiti.

THIRD QUARTER 2014 ACCOMPLISHMENTS

What were the highlights of Delphi's operational and financial results for the third quarter of 2014?

In the third quarter of 2014, the Company achieved the following:

- Average production of 9,461 barrels of oil equivalent per day ("boe/d") in the third quarter of 2014, an increase of eight percent over the comparative quarter in 2013 despite downtime in Montney and Wapiti. This downtime resulted in a reduction of volumes for the third quarter of approximately 1,700 boe/d;

- Improved cash netbacks per barrels of oil equivalent ("boe") in the third quarter of 2014 by 33 percent to $16.34 per boe over the comparative quarter of 2013, resulting in funds from operations of $14.2 million, a 43 percent increase over the third quarter of 2013;

- Increased average field condensate production by 74 percent to 1,227 barrels per day ("bbls/d") in comparison to the third quarter of 2013;

- Increased average Montney production from 3,512 boe/d in the third quarter of 2013 to 5,502 boe/d in the third quarter of 2014, an increase of 57 percent despite downtime in August 2014. The Bigstone Montney project contributed 58 percent of the Company's production during the third quarter of 2014 compared to 40 percent during the comparative quarter of 2013;

- Montney liquids yield was 93 bbls/mmcf in the third quarter of 2014 with field and plant condensate representing 71 percent of the liquids yield and the balance of the liquids yield split between butane at 15 percent and propane at 14 percent;

- Acquired eight gross (3.5 net) sections of Montney rights at East Bigstone for a purchase price of $8.8 million after closing adjustments;

- Closed the sale of certain interests from its Hythe property for net proceeds of $16.0 million after closing adjustments; and

- Successfully drilled, completed and tied-in two gross (1.75 net) Montney wells as part of the Company's capital program. One well was brought on production late in the quarter and the other well was brought on production in the fourth quarter.

Funds from operations in the third quarter of 2014 were $14.2 million or $0.09 per basic share and diluted share, compared to $10.0 million or $0.07 per basic share ($0.06 per diluted share) in the comparative quarter of 2013. The increase in funds from operations from the third quarter of 2013 to the third quarter of 2014 is primarily due to an increase in natural gas, field condensate and natural gas liquids production associated with the liquids-rich Montney development program at East Bigstone in combination with an improvement in realized natural gas and natural gas liquids prices.

For the three months ended September 30, 2014, Delphi realized a $1.4 million loss on its financial commodity risk management contracts.

As at September 30, 2014, the Company's net debt was $165.2 million. On an annualized, third quarter funds from operations basis, Delphi's net debt to funds from operations ratio was 2.9:1. During the third quarter of 2014, the Company's Montney and Wapiti volumes were curtailed due to third party constraints, impacting the third quarter production volumes by approximately 1,700 boe/d and funds from operations by approximately $4.0 million. Including the $4.0 million of funds from operations from the curtailed production, as at September 30, 2014, the Company's net debt to funds from operations ratio would have been 2.3:1.

2014 OUTLOOK AND FORWARD-LOOKING INFORMATION

This management discussion and analysis contains forward-looking statements and forward-looking information within the meaning of applicable Canadian securities laws. These statements relate to future events or the Company's future performance and are based upon the Company's internal assumptions and expectations. All statements other than statements of present or historical fact are forward-looking statements. Forward-looking statements are often, but not always, identified by the use of any of the words "expect", "anticipate", "continue", "estimate", "may", "will", "should", "believe", "intends", "forecast", "plans", "guidance", "budget" and similar expressions.

More particularly and without limitation, this management discussion and analysis contains forward-looking statements and information relating to petroleum and natural gas production estimates and weighting, projected crude oil and natural gas prices, future exchange rates, expectations as to royalty rates, expectations as to transportation and operating costs, expectations as to general and administrative costs and interest expense, expectations as to capital expenditures and net debt, planned capital spending, future liquidity and Delphi's ability to fund ongoing capital requirements through operating cash flows and its credit facilities, supply and demand fundamentals for oil and gas commodities, timing and success of development and exploitation activities, cash availability for the financing of capital expenditures, access to third-party infrastructure, treatment under governmental regulatory regimes and tax laws and future environmental regulations.

Furthermore, statements relating to "reserves" are deemed to be forward-looking statements as they involve the implied assessment, based on certain estimates and assumptions that the reserves described can be profitable in the future.

The forward-looking statements and information contained in this management discussion and analysis are based on certain key expectations and assumptions made by Delphi. The following are certain material assumptions on which the forward-looking statements and information contained in this management discussion and analysis are based: the stability of the global and national economic environment, the stability of and commercial acceptability of tax, royalty and regulatory regimes applicable to Delphi, exploitation and development activities being consistent with management's expectations, production levels of Delphi being consistent with management's expectations, the absence of significant project delays, the stability of oil and gas prices, the absence of significant fluctuations in foreign exchange rates and interest rates, the stability of costs of oil and gas development and production in Western Canada, including operating costs, the timing and size of development plans and capital expenditures, availability of third party infrastructure for transportation, processing or marketing of oil and natural gas volumes, prices and availability of oilfield services and equipment being consistent with management's expectations, the availability of, and competition for, among other things, pipeline capacity, skilled personnel and drilling and related services and equipment, results of development and exploitation activities that are consistent with management's expectations, weather affecting Delphi's ability to develop and produce as expected, contracted parties providing goods and services on the agreed timeframes, Delphi's ability to manage environmental risks and hazards and the cost of complying with environmental regulations, the accuracy of operating cost estimates, the accurate estimation of oil and gas reserves, future exploitation, development and production results and Delphi's ability to market oil and natural gas successfully to current and new customers. Additionally, estimates as to expected average annual production rates assume that no unexpected outages occur in the infrastructure that the Company relies on to produce its wells, that existing wells continue to meet production expectations and any future wells scheduled to come on in the coming year meet timing and production expectations.

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.

Financial outlook information contained in this management discussion and analysis about prospective results of operations, financial position or cash flows is based on assumptions about future events, including economic conditions and proposed courses of action, based on management's assessment of the relevant information currently available. Readers are cautioned that such financial outlook information contained in this management discussion and analysis should not be used for purposes other than for which it is disclosed.

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 and such forward-looking statements should not be unduly relied upon. Since forward-looking statements and information address future events and conditions, by their very nature they involve inherent known and unknown risks and uncertainties. Delphi's actual results, performance or achievements could differ materially from those expressed in, or implied by, these forward-looking statements and, accordingly, no assurance can be given that any of the events anticipated by the forward-looking statements will transpire or occur, or if any of them do so, what benefits Delphi will derive therefrom. Should one or more of these risks or uncertainties materialize, or should assumptions underlying forward-looking statements prove incorrect, actual results may vary 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 from others for scarce resources, the ability to access sufficient capital from internal and external sources, changes in governmental regulation of the oil and gas industry 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 the Company's most recent Annual Information Form and other reports on file with the applicable securities regulatory authorities and may be accessed through the SEDAR website (www.sedar.com).

Readers are cautioned that the foregoing list of factors is not exhaustive. Furthermore, the forward-looking statements contained in this MD&A are made as of the date of this MD&A 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. The forward-looking statements contained in this management discussion and analysis are expressly qualified in their entirety by this cautionary statement.

PRODUCTION

What are the Company's production expectations for 2014?

The Company expects average annual production in 2014 to be between 10,000 and 10,500 boe/d. The production is expected to be split 29 percent to liquids and 71 percent to natural gas.

REVENUES

What does the Company project for crude oil and natural gas prices and the Canadian/United States exchange rate in 2014?

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 the generation of electricity for summer cooling requirements. Over the past five years, multi-stage hydraulic fracturing technology has unlocked significant natural gas resource potential in numerous shale basins in North America which are capable of initially producing at very high rates of natural gas before declining and producing for a long time. The United States has significantly grown its supply of dry gas to meet domestic demand over that same period of time further influencing the dynamics of the natural gas markets.

During the first half of 2014, natural gas storage levels decreased to levels significantly lower than the five year average and last year due to colder than normal average winter temperatures in North America, particularly in the regions of the greatest consumption. As a result, the average price for AECO in the first quarter of 2014 was $5.65 per thousand cubic feet ("mcf") and $4.69 per mcf in the second quarter of 2014. During the second half of 2014, natural gas prices started declining as a result of natural gas storage injections and cooler than normal temperatures during the summer months and warmer than normal temperatures during the fall, causing demand to decline. The average price for AECO during the third quarter of 2014 was $4.02 per mcf. For 2014, Delphi anticipates AECO natural gas prices to average between $4.25 and $4.75 per mcf for 2014.

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 89 - 90 million barrels per day to meet the global requirement for energy. Recently, the strength of the U.S. dollar and forecasted declines in Japanese and European consumption have caused the average WTI price to decline six percent in the third quarter of 2014 compared to the second quarter of 2014. 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 anticipates the demand for crude oil to remain relatively constant on a global basis resulting in WTI averaging between U.S. $90.00 and $100.00 per barrel in 2014.

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.

So far in 2014, the Canadian dollar has weakened relative to the U.S. dollar. The exchange rate is influenced by many variables which will continue to result in volatility. Delphi has assumed that the Canadian dollar will strengthen slightly resulting in an average exchange rate of $1.10 Cdn. to U.S. dollar.

ROYALTIES

What average royalty rate does Delphi expect to pay in 2014?

The Company pays royalties to provincial governments, individuals and companies that own surface and/or mineral rights and Companies that have been granted an overriding royalty. 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 less the cost to deliver the product to market. 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. Crown royalties are also influenced by royalty incentives provided by the provincial governments to stimulate drilling activity by the industry. Delphi expects the royalty regime in Alberta to remain stable throughout 2014. Royalties are not affected by gains or losses realized through the Company's risk management program.

For 2014, Delphi expects its royalty rate, after the deduction for royalty credits and incorporating the higher Crown royalty rates for the increased natural gas prices in the first and second quarter of 2014, will average between 15 and 18 percent of gross revenue, excluding realized and unrealized gains or losses on commodity risk management contracts.

TRANSPORTATION EXPENSES AND OPERATING COSTS

Will Delphi be able to further reduce its costs of production in 2014?

Transportation expenses are costs incurred by the Company to transport its production volumes from the wellhead to the point of sales. In Alberta, transportation expense is influenced by market conditions and availability of existing pipeline capacity. In British Columbia, infrastructure is owned by Spectra Energy Corp. that enables natural gas producers to avoid facility construction in exchange for regulated gathering, processing and transmission fees. These charges are included in transportation expenses.

Delphi expects its transportation expenses to be approximately $3.60 to $3.90 per boe in 2014. Transportation expenses are subject to the availability of pipeline capacity on an interruptible basis in areas of significant production growth by industry. Delphi does not anticipate having any issues moving its production to sales.

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. With the growth in Montney production as a percentage of total production, operating costs are expected to increase due to sour gas processing through non-operated facilities. Operating costs in 2014 are expected to average $8.75 to $9.25 per boe.

GENERAL & ADMINISTRATIVE AND FINANCE COSTS

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

In 2014, Delphi anticipates its general and administrative costs, net of capitalized amounts, to be approximately $2.00 to $2.20 per boe, very similar to 2013. A high level of industry activity may cause an increase in general and administrative expenses due to higher than expected employee retention costs, fees to hire new employees and general cost of 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 funds from operations are less than expected and long term debt is used to fund a larger portion of the capital program than originally anticipated. The Company expects the Canadian prime rate to remain stable in 2014. Interest expense is expected to be approximately $2.00 to $2.20 per boe in 2014.

CAPITAL PROGRAM AND NET DEBT LEVELS

What are the Company's forecast capital expenditures and net debt levels for 2014?

The Company expects 2014 net capital expenditures to be between $100.0 and $105.0 million to drill, complete and tie-in 8 wells with funding from cash flow, the sale of gross overriding royalties, proceeds from disposition and bank indebtedness. The ability to drill, complete and tie-in wells assumes the availability of equipment and field personnel to undertake the operations. Historically, Delphi executes a winter capital program in excess of first quarter cash flow followed by at least one quarter of minimal activity prior to returning to the field with an active summer/fall program.

The Company is targeting net debt at December 31, 2014 to be between $170.0 and $175.0 million.

THIRD QUARTER 2014 OPERATIONAL AND FINANCIAL RESULTS

BUSINESS ENVIRONMENT

What external factors of the business environment did the Company have to contend with in the third quarter of 2014?

The table below outlines the changes in the various benchmark commodity prices and economic parameters which affect the prices received for the Company's production.

Benchmark Prices and Economic Parameters

	Three Months Ended September 30			Nine Months Ended September 30		
	2014	2013	% Change	**2014**	2013	% Change
Natural Gas						
NYMEX (US $/mmbtu)	**3.95**	3.56	11	**4.41**	3.67	20
AECO (CDN $/mcf)	**4.02**	2.44	65	**4.78**	3.05	57
Crude Oil						
West Texas Intermediate (US $/bbl)	**97.21**	105.82	(8)	**99.60**	98.17	1
Edmonton Light (CDN $/bbl)	**97.22**	104.72	(7)	**100.70**	95.22	6
Foreign Exchange						
Canadian to U.S. dollar	**0.92**	0.96	(4)	**0.91**	0.98	(7)
U.S. to Canadian dollar	**1.09**	1.04	5	**1.09**	1.02	7

Natural Gas

In the first half of 2014, the level of natural gas storage decreased to levels below last year and the five year average due to significantly colder than normal average winter temperatures in North America. The significant increase in demand for natural gas resulted in an improvement in the pricing for natural gas. The daily AECO benchmark natural gas price was volatile during the first quarter of 2014, reaching a high of $7.58 per mcf in February and decreasing to $5.28 per mcf in March. The daily AECO benchmark natural gas price was more stable during the second quarter of 2014 compared to the first quarter of 2014, averaging $4.69 per mcf.

The level of natural gas storage in North America has rebounded since the first half of 2014 due to mild summer and fall weather which has enabled the industry to produce record injection levels and stay on track to enter the winter season with healthy storage levels. Increased storage levels have also increased due to a surge in production, particularly in September. For the three and nine months ended September 30, 2014, AECO increased 65 and 57 percent, respectively, compared to the same periods in 2013.

Natural Gas Liquids

Natural gas liquids include ethane, propane, butane, pentane and plant condensate which are generally priced off light oil and natural gas prices. Ethane prices are correlated to natural gas prices while propane and butane prices trade at a discount to light oil prices depending on supply/demand conditions. Strong demand for condensate in Alberta, as a diluent for transporting heavy oil, results in benchmark condensate prices at Edmonton generally trading at a premium to Canadian light oil prices.

Crude Oil

WTI averaged U.S. $97.21 per barrel in the third quarter of 2014, a decrease of eight percent over the comparative period in 2013. For the nine months ended September 30, 2014, WTI increased one percent in comparison to the same period in 2013. Canadian prices experienced a widening basis differential partially offset by a weakening Canadian dollar. Canadian prices decreased seven percent in the three months ended September 30, 2014 compared to the same period in 2013. For the nine months ended September 30, 2014, Edmonton Light increased six percent in comparison to the same period in 2013. Edmonton Light averaged $97.22 per barrel in the third quarter of 2014 compared to $104.72 per barrel in the same period in 2013.

Canadian/United States Exchange Rate

The value of the Canadian dollar against its U.S. counterpart has been declining from $1.01 in January 2013 to $0.94 in December 2013 to $0.91 in September 2014. As a producer of crude oil, a decline in the Canadian dollar has a positive effect on the price received for production. The average Cdn/US exchange rate for the three months ended September 30, 2014 was $0.92.

DRILLING OPERATIONS

How active was Delphi in its drilling program in the first nine months of 2014 and where was the drilling focused?

Delphi's drilling program was focused on the Bigstone Montney formation, drilling 6.0 gross (5.8 net) wells with a success rate of 100 percent. In comparison, Delphi drilled 4.0 gross (4.0 net) wells in the first nine months of 2013, also focused on the Bigstone Montney formation.

	Nine Months Ended September 30, 2014	
	Gross	**Net**
Liquids rich natural gas (>40 bbls/mmcf liquids content)	**6.0**	**5.8**
Success rate (%)	**100**	**100**

CAPITAL INVESTED

How much capital was invested by the Company in the third quarter and first nine months of 2014 and where were the capital expenditures incurred?

During the third quarter of 2014, Delphi invested $29.4 million of capital expenditures and $8.8 million on the acquisition of properties which were partially funded by proceeds on disposition of $16.0 million. During the third quarter of 2014, Delphi directed 61 percent of its capital invested toward drilling, completion and equipping of 2.0 gross (1.8 net) wells and 34 percent on facility expenditures. One well was brought on production late in the quarter and the other well was brought on during the fourth quarter. During the third quarter of 2014, Delphi commenced and completed the construction of the Company's 9 million cubic feet per day ("mmcf/d") South Bigstone compression/dehydration facility and gathering system to handle Delphi production in the area. The Company has also completed pipeline connections to deliver its Montney natural gas and natural gas liquids from its East and South Bigstone facilities to the SemCams K3 processing facility.

During the third quarter of 2014, the Company closed the sale of certain interests from its Hythe property for net proceeds of $16.0 million after closing adjustments. The disposed assets were producing approximately 430 boe/d (55 percent natural gas) and included 23.3 gross (17.7 net) sections of primarily shallow Cretaceous rights. During the third quarter of 2014, the Company closed the acquisition of eight gross (3.5 net) sections of Montney rights directly offsetting Delphi's current Montney production and recent drilling activity at East Bigstone for a purchase price of $8.8 million. The acquisition was funded by the Hythe property disposition.

During the first nine months of 2014, the Company invested $84.0 million of capital expenditures and $8.8 million on the acquisition of properties which were partially funded by proceeds on disposition of $16.0 million. Delphi has invested approximately $58.1 million, or 69 percent, toward the development of its Montney formation at East Bigstone. In the first nine months of 2014, Delphi has drilled 6.0 gross (5.8 net) wells and completed fracture stimulation operations and equipping on 7.0 gross (6.7 net) wells, one of which was drilled during the fourth quarter of 2013. The Company invested $22.2 million, or 26 percent, on facility expenditures. Delphi expanded its 100 percent owned compression and dehydration facility located in East Bigstone by adding another compressor and dehydrator, thereby increasing the capacity to handle an additional 15 mmcf/d of raw natural gas to a total capacity of 45 mmcf/d of raw natural gas and doubling the field condensate tank storage capacity to 6,000 barrels. In addition to the expansion of the East Bigstone facility, Delphi commenced and completed the construction of the Company's 9 mmcf/d South Bigstone compression/dehydration facility and gathering system to handle Delphi production in the area. The Company has also completed pipeline connections to deliver its Montney natural gas and natural gas liquids from its East and South Bigstone facilities to the SemCams K3 processing facility.

On October 1, 2014, Delphi acquired production, undeveloped land and a natural gas processing facility in West Bigstone for a cash purchase price of $8.8 million after closing adjustments. The production consists of approximately 430 boe/d (87 percent natural gas) and 26.3 gross (19.3 net) sections of Cretaceous rights in the greater Bigstone area. As part of the transaction, Delphi has also acquired approximately 40 kilometres of field gathering infrastructure and a 100 percent working interest in an under-utilized 15 mmcf/d sweet shallow cut natural gas processing plant. The acquisition was partially funded by the disposition in the third quarter of 2014 and bank debt. The acquisition complements Delphi's existing West Bigstone assets and provides Delphi with direct-to-sales infrastructure for future Montney development at West Bigstone.

As of September 30, 2014, Delphi has a working interest in a total of 102.5 gross (87.3 net) sections of undeveloped land as part of 137.5 gross (116.7 net) sections of total land prospective for liquids-rich natural gas in the Montney formation, situated at its core area of Bigstone.

	Three Months Ended September 30			Nine Months Ended September 30		
	2014	2013	% Change	**2014**	2013	% Change
Land	**829**	53	1,464	**1,080**	227	376
Seismic	**34**	31	10	**114**	32	256
Drilling, completions and equipping	**17,821**	11,654	53	**58,114**	38,345	52
Facilities	**10,007**	730	1,271	**22,154**	4,114	439
Capitalized expenses	**597**	547	9	**2,391**	1,609	49
Other	**62**	-	-	**146**	5	2,820
Capital invested	**29,350**	13,015	126	**83,999**	44,332	89
Disposition of properties	**(15,964)**	(42)	37,910	**(15,964)**	(3,319)	381
Net capital invested	**13,386**	12,973	3	**68,035**	41,013	66
Acquisition of undeveloped properties	**8,800**	-	-	**8,800**	13,664	(36)
Total capital invested	**22,186**	12,973	71	**76,835**	54,677	41

PRODUCTION

What factors contributed to the production volumes?

Production volumes for the three months ended September 30, 2014 averaged 9,461 boe/d, an 8 percent increase over the comparative period in 2013. Production volumes in the third quarter of 2014 were negatively impacted by the curtailment of the Company's Montney and Wapiti production due to repairs to a third party natural gas liquids pipeline and a scheduled gas plant turnaround. This resulted in a reduction of volumes for the third quarter of approximately 1,700 boe/d. During the third quarter of 2014, 3.0 gross (2.8 net) wells were brought on production, of which one well was brought on late in the quarter. Production volumes from the Montney development for the three months ended September 30, 2014 averaged 5,502 boe/d, an increase of 57 percent over the comparative period.

Production volumes for the first nine months of 2014 averaged 10,050 boe/d, a 26 percent increase over the comparative period in 2013. Production volumes have increased as a result of the Company's successful drilling program in the Montney formation at Bigstone, partially offset by natural declines. During the first quarter of 2014, 2.0 gross (1.9 net) wells were brought on production, of which 1.0 well came on stream during the latter part of the quarter. During the second quarter of 2014, 1.0 gross (1.0 net) well was brought on stream and during the third quarter of 2014, 3.0 gross (2.8 net) wells were brought on production, of which one well was brought on late in the third quarter.

The Company's production portfolio for the third quarter of 2014 was weighted 13 percent to field condensate, 14 percent to natural gas liquids, two percent to crude oil and 71 percent to natural gas. This compares to a production portfolio for the comparative quarter in 2013 weighted eight percent to field condensate, 15 percent to natural gas liquids, three percent to crude oil and 74 percent to natural gas. The increase in field condensate and natural gas liquids production from the third quarter of 2013 to 2014 is due to the liquids-rich nature of the Company's Montney lands at Bigstone. For the third quarter of 2014, the Montney production consisted of 21 percent field condensate, 15 percent natural gas liquids and 64 percent natural gas.

Field condensate as a percentage of total liquids increased to 45 percent for the three months ended September 30, 2014 compared to 30 percent for the comparative quarter in 2013. Total liquids production for the third quarter of 2014 increased 18 percent compared to the third quarter of 2013.

	Three Months Ended September 30			Nine Months Ended September 30		
	2014	2013	% Change	**2014**	2013	% Change
Field condensate (bbls/d)	**1,227**	705	74	**1,348**	601	124
Natural gas liquids (bbls/d)	**1,356**	1,294	5	**1,551**	1,200	29
Crude oil (bbls/d)	**169**	330	(49)	**210**	320	(34)
Total crude oil and natural gas liquids	**2,752**	2,329	18	**3,109**	2,121	47
Natural gas (mcf/d)	**40,251**	38,807	4	**41,646**	35,209	18
Total (boe/d)	**9,461**	8,797	8	**10,050**	7,989	26

REALIZED SALES PRICES

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

For the three and nine months ended September 30, 2014, Delphi realized an average sales price of $38.69 per boe and $42.82 per boe, respectively, a 17 percent and 30 percent increase when compared to the same periods in 2013.

For the three months ended September 30, 2014, Delphi's realized natural gas price increased 20 percent in comparison to the same period in 2013. The increase is due to a significant improvement in the average daily AECO benchmark price partially offset by a decrease in realized gains on physical commodity risk management contracts and an increase in loss on financial commodity risk management contracts. For the nine months ended September 30, 2014, Delphi's realized natural gas price increased 30 percent in comparison to the same period in 2013. The increase is due to an improvement in the average daily AECO benchmark price and an increase in the premium received for Delphi's heat content and marketing arrangements partially offset by realized losses on physical and financial commodity risk management contracts. The increase in the revenue received for Delphi's heat content and marketing arrangements is primarily due to an increase in the Chicago Monthly Index relative to AECO for volumes sold on the Alliance pipeline.

Realized crude oil and field condensate prices decreased one percent in the third quarter of 2014 compared to the same period in 2013. The decrease is due to a decline in Edmonton light partially offset by a decrease in realized losses on financial commodity risk management contracts and the quality differential. Realized crude oil and field condensate prices increased nine percent in the first nine months of 2014 compared to the same period in 2013. The increase is due to an improvement in Edmonton light and a premium partially offset by an increase in loss on financial commodity risk management contracts. The differential or premium received is primarily due to the pricing obtained for the Company's field condensate relative to Edmonton light.

For the three and nine months ended September 30, 2014, realized natural gas liquids prices increased 11 percent and 20 percent, respectively, compared to the same periods in 2013. The increase in the realized natural gas liquids price from the third quarter of 2013 to that of 2014 is primarily due to an increase in price for propane and butane partially offset by a decrease in price for ethane, pentane and plant condensate in combination with the change in production mix of these products. The increase in the realized natural gas liquids price from the first nine months of 2013 to that of 2014 is due to an increase in price for propane, butane, pentane and plant condensate offset by a decrease in price for ethane in combination with the change in production mix of these products.

	Three Months Ended September 30			Nine Months Ended September 30		
	2014	2013	% Change	**2014**	2013	% Change
AECO ($/mcf)	**4.02**	2.44	65	**4.78**	3.05	57
Heating content and marketing arrangements ($/mcf)	**0.38**	0.38	-	**0.58**	0.34	71
Realized price before risk management contracts ($/mcf)	**4.40**	2.82	56	**5.36**	3.39	58
Gain (loss) on physical contracts ($/mcf)	**0.01**	0.16	(96)	**(0.03)**	0.01	(400)
Gain (loss) on financial contracts ($/mcf)	**(0.32)**	0.44	(173)	**(0.73)**	0.14	(621)
Realized natural gas price ($/mcf)	**4.09**	3.42	20	**4.60**	3.54	30
Edmonton Light ($/bbl)	**97.22**	104.72	(7)	**100.70**	95.22	6
Quality differential ($/bbl)	**(4.14)**	(7.25)	(43)	**0.87**	(5.43)	-
Realized price before risk management contracts ($/bbl)	**93.08**	97.47	(5)	**101.57**	89.79	(13)
Loss on financial contracts ($/bbl)	**(2.14)**	(5.98)	(64)	**(5.98)**	(2.41)	148
Realized oil and field condensate price ($/bbl)	**90.94**	91.49	(1)	**95.59**	87.38	9
Realized natural gas liquids price ($/bbl)	**53.20**	48.02	11	**56.59**	47.05	20
Total realized sales price ($/boe)	**38.69**	32.94	17	**42.82**	32.89	30

RISK MANAGEMENT ACTIVITIES

What is Delphi's risk management strategy over the sales price it receives for its production and what contracts are in place to mitigate the risk of price 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.

With respect to financial contracts, which are derivative financial instruments, management has elected not to use hedge accounting and consequently records the fair value of its natural gas and crude oil financial contracts on the statement of financial position at each reporting period with the change in the fair value being classified as unrealized gains and losses in the consolidated statement of earnings. Natural gas 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 also included in the consolidated statement of earnings.

The Company has managed the price applicable to production volumes through the following contracts:

Physical Contracts

Time Period	Type of Contract	Quantity Contracted	Price ($/unit)	
October 2014	Natural Gas – fixed	7,500 GJ/d	$3.97	Cdn
November 2014	Natural Gas – fixed	10,000 GJ/d	$3.52	Cdn
December 2014	Natural Gas – fixed	5,000 GJ/d	$4.10	Cdn

Financial Contracts

Time Period	Type of Contract	Quantity Contracted	Price Floor ($/unit)		Price Ceiling ($/unit)	
April 2013 – April 2015	Natural Gas – fixed	3,000 GJ/d	$3.54	Cdn	$3.54	Cdn
April 2013 – December 2015	Natural Gas – fixed	3,000 GJ/d	$3.27	Cdn	$3.27	Cdn
April 2013 – December 2016	Natural Gas – fixed	3,000 GJ/d	$3.40	Cdn	$3.40	Cdn
June 2013 – December 2016	Natural Gas – fixed	6,000 GJ/d	$3.45	Cdn	$3.45	Cdn
August 2013 – October 2014	Natural Gas – fixed	3,000 mmbtu/d	$3.71	U.S.	$3.71	U.S.
January 2014 – October 2014	Natural Gas – fixed	2,500 GJ/d	$3.65	Cdn	$3.65	Cdn
April 2014 – October 2014	Natural Gas – fixed	5,000 GJ/d	$3.40	Cdn	$3.40	Cdn
April 2014 – October 2014	Natural Gas – fixed	5,000 GJ/d	$3.25	Cdn	$3.25	Cdn
January 2015 – December 2015	Natural Gas – fixed	2,500 GJ/d	$3.67	Cdn	$3.67	Cdn
January 2015 – December 2015	Natural Gas – fixed	5,000 GJ/d	$3.69	Cdn	$3.69	Cdn
January 2015 – December 2015	Natural Gas – fixed	2,500 GJ/d	$3.80	Cdn	$3.80	Cdn
April 2015 – October 2015	Natural Gas – fixed	2,500 GJ/d	$3.49	Cdn	$3.49	Cdn
April 2015 – October 2015	Natural Gas – fixed	2,500 GJ/d	$3.62	Cdn	$3.62	Cdn
January 2016 – December 2016	Natural Gas – fixed	2,500 GJ/d	$3.69	Cdn	$3.69	Cdn
January 2017 – December 2017	Natural Gas – fixed	2,500 GJ/d	$3.75	Cdn	$3.75	Cdn
January 2014 – December 2014	Crude Oil – call option	600 bbls/d		-	$90.00	U.S.
January 2014 – December 2014	Crude Oil – put option (1)	1,000 bbls/d	$110.15	Cdn		-
January 2015 – December 2015	Crude Oil – put option (1)	250 bbls/d	$101.00	Cdn		-
January 2015 – December 2015	Crude Oil – put option (1)	250 bbls/d	$100.85	Cdn		-

(1) The put contract for 1,000 bbls/d from January 2014 to December 2014 has a deferred cost of $4.01 per barrel. The put contracts for 250 bbls/d from January 2015 to December 2015 have a deferred cost of $6.00 per barrel and $5.85 per barrel, respectively.

The fair value of the financial contracts outstanding as at September 30, 2014 is estimated to be a net liability of $4.3 million. 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.

For the three and nine months ended September 30, 2014, the derivative commodity contracts resulted in realized losses of $1.4 million and $10.8 million, respectively, compared to realized gains of $1.0 million and $0.8 million, respectively, in the same periods in 2013.

For the three and nine months ended September 30, 2014, Delphi recorded an unrealized gain on its risk management contracts of $4.7 million and $1.5 million, respectively. The unrealized gain recognized for the three and nine months ended September 30, 2014 is the difference between the fair values of the risk management contracts outstanding as at September 30, 2014 and the fair values as at June 30, 2014 and December 31, 2013, respectively.

The Company accounts for 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 for the three and nine months ended September 30, 2014 compare to 2013 and what factors contributed to the change?

Delphi generated revenue of $35.1 million in the third quarter of 2014, a 37 percent increase over the comparative period in 2013. The increase in revenues is primarily due to higher natural gas, field condensate and natural gas liquids production in combination with an improvement in realized sales prices for natural gas and natural gas liquids partially offset by a decrease in crude oil revenue due to lower production volumes as a result of natural declines.

Delphi generated revenue of $128.3 million in the first three quarters of 2014, an 81 percent increase over the comparative period in 2013. The increase in revenues in primarily due to higher natural gas, field condensate and natural gas liquids production in combination with an improvement in realized sales prices for this production partially offset by a decrease in crude oil revenue due to lower production volumes as a result of natural declines.

For the three and nine months of 2014, field condensate and natural gas liquids contributed 49 percent and 48 percent, respectively, of total revenues compared to 46 percent and 42 percent, respectively, in the comparative periods in 2013.

	Three Months Ended September 30			Nine Months Ended September 30		
	2014	2013	% Change	**2014**	2013	% Change
Natural gas	**16,302**	10,075	62	**60,998**	32,506	88
Natural gas physical contract gain (loss)	**23**	575	(96)	**(341)**	119	(387)
Field condensate	**10,475**	6,196	69	**37,602**	14,499	159
Natural gas liquids	**6,637**	5,717	16	**23,960**	15,414	55
Crude oil	**1,479**	3,085	(52)	**5,598**	8,077	(31)
Sulphur	**201**	18	1,017	**519**	356	46
Total	**35,117**	25,666	37	**128,336**	70,971	81

ROYALTIES

What were royalty costs in the third quarter and first nine months of 2014?

For the three and nine months ended September 30, 2014, royalties increased $1.9 million and $11.7 million, respectively, compared to the same periods in 2013.

Crown royalties for the three months ended September 30, 2014, decreased six percent in comparison to the comparative period in 2013 primarily as a result of higher production volumes from wells which take advantage of Alberta royalty incentive programs and a reduction in crude oil royalties as production volumes decrease due to natural declines. Over the same respective periods, gross overriding royalties increased $2.3 million due to the addition of new wells in the Montney area which have been encumbered by a gross overriding royalty in combination with an increase in sales price and production from the Montney development.

Crown royalties for the nine months ended September 30, 2014, increased 18 percent compared to the same period in 2013, primarily due to higher royalties paid on natural gas, field condensate and natural gas liquids. This is a result of an improvement in commodity prices for natural gas, field condensate and natural gas liquids in combination with higher production of these commodities. Over the same respective periods, Crown royalty credits decreased $0.3 million primarily due to a gas cost allowance adjustment relating to 2013 production periods. Gross overriding royalties have increased $9.5 million in the nine months ended September 30, 2014, compared to the same period in 2013. The increase in gross overriding royalties over the respective periods is due to the addition of new wells in the Montney area which have been encumbered by a gross overriding royalty in combination with an increase in sales price and production from the Montney development.

	Three Months Ended September 30			Nine Months Ended September 30		
	2014	2013	% Change	**2014**	2013	% Change
Crown royalties	**3,019**	3,202	(6)	**11,504**	9,715	18
Royalty credits	**(1,476)**	(1,349)	9	**(3,808)**	(4,133)	(8)
Crown royalties – net	**1,543**	1,853	(17)	**7,696**	5,582	38
Gross overriding royalties	**3,478**	1,215	186	**12,537**	2,998	318
Total	**5,021**	3,068	64	**20,233**	8,580	136
Per boe	**5.77**	3.79	52	**7.37**	3.93	87

What were the average royalty rates paid on production in the third quarter and nine months of 2014?

For the three and nine months ended September 30, 2014, the average royalty rate increased to 14.3 percent and 15.7 percent, respectively, up from 12.2 percent and 12.1 percent in the respective comparative periods in 2013. For the three and nine months ended September 30, 2014, the Crown royalty rate decreased compared to the same periods in 2013, primarily as a result of an increase in production from wells that take advantage of the Alberta royalty incentive programs.

For the three and nine months ended September 30, 2014, the average gross overriding royalty rate increased to 9.9 percent and 9.7 percent, respectively, up from 4.8 percent and 4.2 percent in the respective comparative periods in 2013. The increase is primarily due to new wells with high production levels brought on since the third quarter of 2013 encumbered by a gross overriding royalty.

	Three Months Ended September 30			Nine Months Ended September 30		
	2014	2013	% Change	**2014**	2013	% Change
Crown rate – net of royalty credits	**4.4%**	7.4%	(41)	**6.0%**	7.9%	(24)
Gross overriding rate	**9.9%**	4.8%	106	**9.7%**	4.2%	131
Average rate	**14.3%**	12.2%	17	**15.7%**	12.1%	30

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

OPERATING EXPENSES

How do operating expenses in the third quarter and first nine months of 2014 compare to 2013?

Production costs for the three months ended September 30, 2014 increased seven percent compared to the same period in 2013. The increase is primarily due to processing fees associated with the Company's new Montney production, which is processed for natural gas liquids at third party facilities and plant turnaround costs partially offset by a $0.2 million equalization credit related to prior periods.

Production costs for the nine months ended September 30, 2014 increased 35 percent compared to the same period in 2013. The increase is primarily due to equipment rental, trucking charges, processing fees associated with the Company's new Montney production and plant turnaround costs. Production costs in the first nine months of 2014 were impacted by a $0.4 million plant equalization related to the Company's 2013 Montney production and a $0.2 million equalization credit in Hythe related to prior periods. Production costs in the first nine months of 2013 were reduced by $0.4 million of equalizations related to prior production periods.

Delphi earns processing income for third party production volumes going through facilities owned by the Company. 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 September 30			Nine Months Ended September 30		
	2014	2013	% Change	**2014**	2013	% Change
Production costs	**8,560**	8,035	7	**27,691**	20,506	35
Processing income	**(649)**	(479)	35	**(1,989)**	(2,418)	(18)
Total	**7,911**	7,556	5	**25,702**	18,088	42
Per boe	**9.09**	9.34	(3)	**9.37**	8.29	13

TRANSPORTATION EXPENSES

What factors contributed to the change in transportation costs in the third quarter and first nine months of 2014?

For the three and nine months ended September 30, 2014, transportation expenses increased 16 percent and 28 percent over the comparative time periods in 2013. The increase in transportation expenses is primarily due to the increased Montney production. Transportation expenses on a per boe basis, for the three and nine months ended September 30, 2014 have increased eight and two percent, respectively, compared to the same periods in 2013.

	Three Months Ended September 30			Nine Months Ended September 30		
	2014	2013	% Change	**2014**	2013	% Change
Total	**3,363**	2,904	16	**10,278**	8,018	28
Per boe	**3.87**	3.59	8	**3.75**	3.68	2

GENERAL AND ADMINISTRATIVE

How do general and administrative costs in the third quarter and first nine months of 2014 compare to 2013?

General and administrative ("G&A") expenses (after recoveries and allocations) for the three months ended September 30, 2014 are comparable to the same period in 2013.

G&A expenses (after recoveries and allocations) for the nine months ended September 30, 2014 decreased two percent compared to the same period in 2013. Gross expenses in the first nine months of 2014 increased 18 percent compared to the first nine months of 2013 primarily due to higher personnel costs. Over the same respective period, overhead recoveries increased $0.5 million due to a larger capital program in combination with a higher total number of wells drilled. Salary allocations increased 46 percent in the first nine months of 2014 compared to the same period in 2013 due to an increase in personnel costs.

Delphi is committed to delivering strong growth and believes a strong team is paramount to achieve this goal.

	Three Months Ended September 30			Nine Months Ended September 30		
	2014	2013	% Change	**2014**	2013	% Change
Gross expenses	**2,641**	2,607	1	**9,028**	7,670	18
Overhead recoveries	**(369)**	(388)	(5)	**(1,468)**	(963)	52
Salary allocations	**(832)**	(760)	9	**(2,984)**	(2,046)	46
General and administrative expenses	**1,440**	1,459	(1)	**4,576**	4,661	(2)
Per boe	**1.65**	1.80	(8)	**1.67**	2.14	(22)

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 and restricted share units ("RSU's") granted to employees, directors and key consultants of the Company. The fair value of RSU's is based on the Company's closing share price on the last business day immediately preceding the vesting date or the Company's closing share price on the last business day immediately preceding the statement of financial position date. The fair value of all options granted is estimated at the date of grant using the Black-Scholes option pricing model.

Share-based compensation expense related to the Company's option plan increased 24 percent and three percent in the three and nine months ended September 30, of 2014, respectively, compared to the same periods in 2013. The increase is primarily due to the granting of 2.0 million stock options in the second quarter of 2014 in combination with a higher weighted average fair value per vesting option.

During the nine months ended September 30, 2014, Delphi granted 2.2 million stock options to employees and consultants with a weighted average fair value of $1.20 per option. As at September 30, 2014, 12.8 million stock options were outstanding with a weighted average exercise price of $1.92 per option.

Share-based compensation expense related to the Company's RSU's decreased in the third quarter of 2014 in comparison to the same period in 2013. The decline is due to the decrease in the Company's closing share price used for the calculation of the expense for the second quarter of 2014 to the third quarter of 2014 for vested, unpaid units. Share-based compensation expense related to the Company's RSU's increased in the first nine months of 2014 in comparison to the same period in 2013. The increase in the expense related to the RSU's is a combination of a higher closing share price used for calculating the expense related to vested and paid RSU's and the fair value of the outstanding RSU's as at September 30, 2014 compared to September 30, 2013.

Capitalized share-based compensation decreased in the third quarter and first nine months of 2014 in comparison to the same periods in 2013 as a result of a re-allocation of the capitalized expense related to the RSU's.

During the nine months ended September 30, 2014, Delphi granted 0.5 million restricted share units to employees and consultants. During the nine months ended September 30, 2014, 0.6 million restricted share units vested resulting in a cash expense, net of capitalization, of $1.9 million. As at September 30, 2014, 1.4 million restricted share units were outstanding.

	Three Months Ended September 30			Nine Months Ended September 30		
	2014	2013	% Change	**2014**	2013	% Change
Share-based compensation – Options	**646**	519	24	**1,656**	1,604	3
Share-based compensation – RSU's	**129**	463	(72)	**3,041**	1,389	119
Capitalized costs	**(144)**	(299)	(52)	**(609)**	(955)	(36)
Net	**631**	684	(8)	**4,088**	2,039	100
Per boe	**0.73**	0.84	(13)	**1.49**	0.93	60

GAIN ON PROPERTY DISPOSITIONS

What does the gain on property dispositions relate to?

During the third quarter of 2014, Delphi completed the sale of certain interests from its Hythe property for net proceeds of $16.0 million. The interests sold had a net book value of $8.5 million, including decommissioning liabilities of $2.8 million, resulting in a gain of $7.5 million. The Company also exchanged assets with a net book value of $69 thousand for assets with a fair value of $1.3 million, resulting in a gain of $1.2 million.

FINANCE COSTS

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

For the three months ended September 30, 2014, interest charges are comparable to the same period in 2013. Although the Company's average debt balance for the third quarter of 2014 is higher than the average debt balance for the third quarter of 2013, the Company's effective interest rate decreased as a result of lower interest charged on the Company's outstanding bankers' acceptances.

For the nine months ended September 30, 2014, interest charges increased 30 percent compared to the same period in 2013, as a result of a higher average debt balance in combination with higher interest rates charged on the Company's outstanding debt. The bankers' acceptances outstanding at September 30, 2014 have terms ranging from 60 to 180 days and a weighted average effective interest rate of 4.2 percent over the term.

Accretion and finance charges are non-cash and comprised of accretion expense on the Company's decommissioning obligations and the accretion of the Company's subordinated debt.

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 one to 63 years. The increase in accretion expense is due to a higher decommissioning obligation as at September 30, 2014 compared to the same period in 2013. The decommissioning obligation increased primarily due to changes in estimates. During the fourth quarter of 2013, the Company revised its estimates to abandon and reclaim its crude oil and natural gas properties.

The finance charge associated with the Company's subordinated debt is based on the effective interest rate method in order to accrete the subordinated debt balance to its face value of $20.0 million plus a deferred fee of 1.5 percent.

	Three Months Ended September 30			Nine Months Ended September 30		
	2014	2013	% Change	**2014**	2013	% Change
Interest	**1,717**	1,701	1	**5,539**	4,265	30
Accretion	**293**	212	38	**873**	579	51
Finance charges	**116**	31	274	**344**	84	310
Total finance costs	**2,126**	1,944	9	**6,756**	4,928	37
Interest per boe	**1.97**	2.10	(6)	**2.02**	1.96	3
Accretion per boe	**0.34**	0.26	31	**0.32**	0.27	19
Finance charges per boe	**0.13**	0.04	225	**0.13**	0.04	225

What has the Company done to protect itself against an increase in interest rates?

The Company has an interest rate swap transaction on borrowings through bankers' acceptances in the amount of $20.0 million maturing on February 28, 2015. The swap transaction has a fixed interest rate of 1.25 percent.

DEPLETION AND DEPRECIATION

How has the Company's depletion and depreciation rate and expense changed in the third quarter and first nine months of 2014 compared to 2013?

Depletion and depreciation for the three months ended September 30, 2014 increased nine percent compared to the same period in 2013 primarily due to higher depletion as a result of an increase in production volumes and a slight increase in the depletion rate. The depletion rate in the third quarter of 2014 increased as a result of higher future development costs partially offset by an increase in reserves.

Depletion and depreciation for the nine months ended September 30, 2014 increased 21 percent in comparison to the same period in 2013. The increase is primarily due to higher depletion as a result of an increase in production volumes partially offset by a decrease in the depletion rate. The depletion rate has decreased as a result of additions to the reserve base partially offset by an increase in the depletion base due to capital additions and higher future development costs.

	Three Months Ended September 30			Nine Months Ended September 30		
	2014	2013	% Change	**2014**	2013	% Change
Depletion and depreciation	**10,236**	9,402	9	**30,919**	25,586	21
Depletion and depreciation per boe	**11.76**	11.62	1	**11.27**	11.73	(4)

INCOME TAXES

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

Delphi recorded a deferred income tax expense of $4.2 million and $6.5 million for the three and nine months ended September 30, 2014, respectively. The increase in the deferred income tax expense is due to an increase in net earnings. Deferred taxes arise from differences between the accounting and tax bases of the Company's assets and liabilities.

Delphi does not anticipate it will be cash taxable before 2017.

	Three Months Ended September 30			Nine Months Ended September 30		
	2014	2013	% Change	**2014**	2013	% Change
Deferred income tax	**4,215**	(237)	-	**6,480**	1,020	535
Per boe	**4.84**	(0.29)	-	**2.36**	0.47	402

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 and is used as a measure to analyze performance. Delphi considers funds from operations 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 calculated as cash flow from operating activities before accretion on long term and subordinated debt, decommissioning expenditures and changes in non-cash working capital.

How do cash flow from operating activities and funds from operations in the first three and nine months of 2014 compare to 2013?

Delphi's cash flow from operating activities of $8.4 million for the three months ended September 30, 2014 decreased six percent from the $8.9 million generated in the same period in 2013. The decrease in cash flow from operations in the third quarter of 2014 from the third quarter of 2013 is primarily due higher decommissioning expenditures, a change in non-cash working capital, higher royalties, realized losses on commodity risk management contracts, operating expenses and transportation expenses partially offset by an increase in crude oil and natural gas sales. In the three months ended September 30, 2014, Delphi generated funds from operations of $14.2 million, up 43 percent from the $10.0 million for the same period in 2013. The increase in funds from operations is primarily due to higher crude oil and natural gas sales partially offset by an increase in royalties, realized losses on commodity risk management contracts, operating expenses and transportation expenses.

Delphi's cash flow from operating activities of $51.0 million for the nine months ended September 30, 2014 increased 97 percent from the 25.9 million generated in the same period in 2013. In the nine months ended September 30, 2014, Delphi generated funds from operations of $49.3 million, up 78 percent from the $27.8 million for the same period in 2013 and greater than funds from operations in total of $39.1 million for all of 2013. The increase in cash flow from operating activities and funds from operations is primarily due to higher crude oil and natural gas sales and a decrease in decommissioning expenditures partially offset by an increase in royalties, realized losses on commodity risk management contracts, operating and transportation expenses, interest costs and the pay out of vested restricted share units.

	Three Months Ended September 30			Nine Months Ended September 30		
	2014	2013	% Change	**2014**	2013	% Change
Cash flow from operating activities	**8,410**	8,910	(6)	**51,035**	25,920	97
Accretion of subordinated and long term debt	**(477)**	735	(165)	**(49)**	524	(109)
Decommissioning expenditures	**445**	179	(149)	**1,074**	1,486	(28)
Change in non-cash working capital	**5,843**	148	3,848	**(2,770)**	(167)	1,559
Funds from operations	**14,221**	9,972	43	**49,290**	27,763	78

NET EARNINGS

What factors contributed to the earnings in the third quarter and first nine months of 2014?

For the three months ended September 30, 2014, Delphi recorded net earnings of $12.2 million ($0.08 per diluted share), compared to net earnings of $1.2 million ($0.01 per diluted share) in the same period in 2013. The increase in net earnings is primarily due to an increase in crude oil and natural gas sales, unrealized gains on commodity risk management contracts and gain on property dispositions partially offset by an increase in royalties, realized losses on commodity risk management contracts, operating costs, transportation expenses, depletion and depreciation expense, interest costs and deferred income tax.

For the nine months ended September 30, 2014, Delphi recorded net earnings of $18.3 million ($0.11 per diluted share), compared to net earnings of $4.5 million ($0.03 per diluted share) in the same period in 2013. The increase in net earnings is primarily due to an increase in crude oil and natural gas sales and gain on property dispositions partially offset by an increase in royalties, realized losses on commodity risk management contracts, operating costs, transportation costs, share-based compensation, depletion and depreciation expense, interest costs and deferred income tax expense as well as a decrease in unrealized gains on commodity risk management contracts.

CASH NETBACK AND EARNINGS ANALYSIS

How do Delphi's netbacks achieved in the third quarter and first nine months of 2014 compare to 2013?

Delphi's production is predominantly natural gas, therefore, the Company's operating and cash netbacks are primarily driven by the price received for natural gas. Delphi continues to focus its drilling on liquids-rich natural gas plays in order to mitigate low natural gas prices and to strengthen its operating and cash netback per boe.

For the three months ended September 30, 2014, Delphi's cash netback per boe increased 33 percent compared to the same period in 2013. The increase in the cash netback per boe from the third quarter of 2013 to that of 2014 is due to improved realized sales prices in combination with a higher liquids yield and a reduction in operating, general and administrative and interest expenses partially offset by an increase in royalties and transportation expenses.

For the nine months ended September 30, 2014, Delphi's cash netback per boe increased 41 percent compared to the same period in 2013. The increase in the cash netback per boe from the first nine months of 2013 to that of 2014 is due to improved realized sales prices in combination with a higher liquids yield and a reduction in general and administrative expenses partially offset by higher royalties, operating expenses, transportation costs, paid out restricted share units and interest costs.

	Three Months Ended September 30			Nine Months Ended September 30		
	2014	2013	% Change	**2014**	2013	% Change
Barrels of oil equivalent ($/boe)						
Realized sales price	**38.69**	32.94	17	**42.82**	32.89	30
Royalties	**5.77**	3.79	52	**7.37**	3.93	88
Operating expenses	**9.09**	9.34	(3)	**9.37**	8.29	13
Transportation	**3.87**	3.59	8	**3.75**	3.68	2
Operating netback	**19.96**	16.22	23	**22.33**	16.99	31
General and administrative expenses	**1.65**	1.80	(8)	**1.67**	2.14	(22)
Paid out restricted share units	**-**	-	-	**0.68**	0.16	325
Interest	**1.97**	2.10	(6)	**2.02**	1.96	3
Cash netback	**16.34**	12.32	33	**17.96**	12.73	41
Unrealized gain on commodity risk contracts	**(5.43)**	(1.61)	237	**(0.57)**	(1.38)	(59)
Share-based compensation expense	**0.73**	0.84	(13)	**0.81**	0.77	5
Gain on dispositions	**(10.00)**	(0.05)	19,900	**(3.17)**	(1.44)	120
Loss on decommissioning	**-**	0.02	-	**0.14**	0.23	(39)
Depletion and depreciation	**11.76**	11.62	1	**11.27**	11.73	(4)
Accretion and finance charges	**0.47**	0.30	57	**0.44**	0.30	47
Deferred income taxes	**4.84**	(0.29)	-	**2.36**	0.47	402
Net earnings	**13.97**	1.49	838	**6.68**	2.05	226

SELECTED INFORMATION

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

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

In the first quarter of 2012, due to the continued deterioration of the natural gas price environment, the Company completed a strategic disposition of its non-operated light oil interests in the Hythe area and minor offsetting lands in order to develop its assets in the Bigstone Montney formation. In the third quarter of 2012, Delphi completed another strategic disposition of its working interests of Cardium oil assets in order to temporarily reduce debt and to fund the Company's ongoing capital program. Despite the dispositions the Company completed in 2012, production volumes only decreased seven percent in the twelve months of 2012 when compared to the same period in 2011 as a result of its successful 2012 drilling program in Bigstone.

In 2013, Delphi continued to focus on exploiting its liquids-rich resource at Bigstone, Alberta. The Company completed, tied-in and placed on production 5.0 net wells which utilized the Company's new slickwater hybrid completion technique which has significantly decreased initial production decline rates and improved productivity of reservoir condensate. Production in the fourth quarter of 2013 increased 24 percent in comparison to the same quarter in 2012 due to the Company's successful capital program. For the year ended December 31, 2013, Delphi's average corporate natural gas liquids and field condensate yield has increased by 51 percent to 53 barrels per million cubic feet compared to 2012.

In the first six months of 2014, Delphi achieved record production of 10,349 boe/d and despite downtime in two of its core properties in the third quarter of 2014, production for the first nine months of 2014 averaged 10,050 boe/d representing a 26 percent increase over the same comparative period of 2013. The increase in production is reflective of the capital invested in the development of the Montney play at East Bigstone. Delphi drilled a total of 6.0 gross (5.8 net) wells and has brought on production 6.0 gross (5.7 net) wells, of which one well was drilled during the fourth quarter of 2013. During the third quarter of 2014, the Company disposed of certain interests from its Hythe property for net proceeds of $16.0 million, after closing adjustments. The disposed assets were producing approximately 430 boe/d (55 percent natural gas) and included 23.3 gross (17.7 net) sections of land. The proceeds of the disposition were used to partially fund an acquisition of Montney rights at East Bigstone for $8.8 million, after closing adjustments, and an acquisition of approximately 430 boe/d (87 percent natural gas), 26.3 gross (19.3 net) sections of undeveloped land and a natural gas processing plant in West Bigstone for $8.8 million, after closing adjustments, on October 1, 2014. During the first quarter of 2014, the Company's senior lenders completed their annual review of the syndicated credit facility resulting in a $30.0 million increase in the borrowing base to $170 million.

Natural gas prices over the past two years have generally reflected the cyclical nature of demand. Higher prices are usually 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 2012, due to higher than normal average winter temperatures in North America and high inventory levels of natural gas, Canadian natural gas prices decreased to ten year lows with an average spot price for AECO of $2.39 per mcf. In 2013 and so far in 2014, prices for natural gas experienced some improvements due to cooler than average temperatures experienced in North America in 2013 and early 2014. Although prices for natural gas in the third quarter of 2014 have improved since 2013, the cooler than average summer temperatures and warmer than average fall temperatures have caused demand for natural gas to decrease. In addition to lower demand for natural gas, production has increased causing record high storage injections for the heating season. The average spot price for AECO in 2013 was $3.17 per mcf and $4.78 per mcf in the first nine months of 2014.

Net earnings (loss) of the Company are primarily driven by the difference between the cash netback realized per boe of production versus the Company's depletion and depreciation rate, unrealized losses on commodity risk management contracts and other non-cash charges. Overall finding and development ("F&D") costs were $18.03 per proved plus probable boe in 2012 versus $9.43 per proved plus probable boe in 2013.

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

	Sep. 30, 2014	Jun. 30, 2014	Mar. 31, 2014	Dec. 31, 2013	Sep. 30, 2013	Jun. 30, 2013	Mar. 31, 2013	Dec. 31, 2012
Production								
Oil and field condensate (bbls/d)	**1,396**	1,583	1,697	1,242	1,035	988	735	565
Natural gas liquids (bbls/d)	**1,356**	1,807	1,493	1,286	1,294	1,115	1,189	1,055
Natural gas (mcf/d)	**40,251**	42,040	42,673	38,761	38,807	33,189	33,574	33,654
Barrels of oil equivalent (boe/d)	**9,461**	10,397	10,302	8,988	8,797	7,635	7,520	7,229
Financial								
Petroleum and natural gas revenue	**35,117**	44,173	49,046	29,459	25,666	23,541	21,763	18,858
Funds from operations	**14,221**	14,660	20,409	11,352	9,972	8,408	9,383	6,269
Per share – basic	**0.09**	0.09	0.13	0.07	0.07	0.05	0.06	0.04
Per share – diluted	**0.09**	0.09	0.12	0.07	0.06	0.05	0.06	0.04
Net earnings (loss)	**12,163**	5,439	723	(16,100)	1,208	3,209	56	(29,394)
Per share – basic	**0.08**	0.04	-	(0.11)	0.01	0.02	-	(0.21)
Per share – diluted	**0.08**	0.03	-	(0.11)	0.01	0.02	-	(0.21)

LIQUIDITY AND CAPITAL RESOURCES

Share Capital

How many common shares and stock options are currently outstanding?

As at November 10, 2014, the Company had 155.4 million common shares outstanding and 12.8 million stock options outstanding. The stock options have an average exercise price of $1.92 per option.

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

The common shares of Delphi trade on the TSX under the symbol DEE. The following table summarizes outstanding share data for the three and nine months ended September 30, 2014:

	Three Months Ended September 30, 2014	Nine Months Ended September 30, 2014
Weighted Average Common Shares		
Basic	**155,285**	**154,633**
Diluted	**161,450**	**160,015**
Trading Statistics [1]		
High	**4.53**	**4.53**
Low	**3.41**	**1.81**
Average daily volume	**723.,823**	**862,154**

(1) Trading statistics based on closing price

Sources and Uses of Funds

	Three Months Ended September 30, 2014	Nine Months Ended September 30, 2014
Sources:		
Funds from operations	**14,221**	**49,290**
Disposition of properties	**15,964**	**15,964**
Exercise of stock options	**324**	**2,902**
Change in non-cash working capital	**4,446**	**5,143**
	34,955	**73,299**
Uses:		
Cash and cash equivalents	**14,081**	**11,719**
Capital expenditures	**29,350**	**83,999**
Accretion of subordinated and long term debt	**(477)**	**(49)**
Acquisition of properties	**8,800**	**8,800**
Expenditures on decommissioning	**445**	**1,074**
	52,199	**105,543**
Increase in long term debt	**17,244**	**32,244**

Net Debt

What is liquidity risk and how does the Company manage this risk?

As an oil and gas business, Delphi has a declining asset base and therefore relies on oil and gas property development and acquisitions to replace produced reserves. Future oil and natural gas production and growth in reserves are highly dependent on the success of exploiting the Company's existing asset base and/or acquiring additional lands or reserves. To the extent Delphi is successful or unsuccessful in these operations, cash flow could be increased or reduced.

Liquidity risk is the risk that Delphi will not be able to meet its financial obligations as they become due. Delphi actively manages its liquidity through daily, short term and long term cash, debt and equity management strategies. Such strategies encompass, among other factors: having adequate sources of financing available through its bank credit facilities, forecasting future cash generated from operations based on reasonable production and pricing assumptions, monitoring economic risk management opportunities and maintaining sufficient cash flows for compliance with financial debt covenants.

Delphi generally relies on operating cash flows and its credit facilities to fund ongoing capital requirements and provide liquidity. Future liquidity depends primarily on cash flow generated from operations, existing credit facilities and the ability to access debt and equity markets. From time to time, the Company accesses capital markets to meet its additional financing needs and to maintain flexibility in funding its capital expenditures program. There can be no assurance that future debt or equity financings, or cash generated from operations will be available or sufficient to meet these requirements or other corporate requirements or, if debt or equity financing is available, that it will be on terms acceptable to Delphi.

Delphi's results are affected by external market and risk factors, such as fluctuations in the prices of crude oil and natural gas, movements in foreign currency exchange rates and inflationary pressures on service costs.

How much debt was outstanding on September 30, 2014?

At September 30, 2014, the Company had $99.2 million outstanding in the form of bankers' acceptances, $33.0 million drawn under Canadian-based prime loans, $20.1 million in subordinated debt and a working capital deficiency of $12.9 million for net debt of $165.2 million. Net debt is a non-IFRS term. Delphi's calculation of net debt includes long term and subordinated debt and the working capital deficiency (surplus) before the current portion of 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 annual review of the Company's senior extendible revolving term credit facility was conducted during the first quarter of 2014 resulting in a $30.0 million increase to $170.0 million.

The Company's senior extendible revolving term credit facility with a syndicate of Canadian chartered banks is subject to the banks' semi-annual review 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 25, 2015 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 25, 2016. 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 U.S. 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 U.S. base rate plus 1.00 percent to a maximum of the bank's prime rate or U.S. base rate plus 2.50 percent or from a minimum of bankers' acceptances rate plus a stamping fee of 2.00 percent to a maximum of bankers' acceptances rate plus a stamping fee of 3.50 percent.

As a result of the $30.0 million increase in the syndicated credit facility's borrowing base, the demand floating charge debenture provided to the lenders as security was increased from $200.0 million to $300.00 million. The syndicated credit facility also has a general security agreement over all assets of the Company.

A semi-annual review of the Company's $170.0 million extendible revolving term credit facility will be conducted during the fourth quarter of 2014. The borrowing base of the facilities will be based on the lenders' evaluation of the Company's petroleum and natural gas reserves and commodity prices.

During the third quarter of 2013, Delphi obtained a $20.0 million subordinated demand credit facility with a Canadian energy and resource lender. The debt is secured by the Company's assets and subordinate to the Company's senior credit facility. The debt has a maturity date of December 31, 2014 and may be extended at the option of Delphi for an additional six months, subject to the Company being compliant with the financial covenants of the facility. Delphi anticipates that it will extend the subordinated debt to June 30, 2015. At maturity, the Company expects to repay the subordinated debt through borrowings under its senior credit facility.

The subordinated debt has an annual coupon rate of 8.5 percent with interest payable monthly. A deferred fee of 1.5 percent of the facility is due upon maturity. The subordinated debt of $20.0 million, net of $0.4 million of financing costs is accreted using the effective interest rate method such that the carrying amount of the subordinated debt will be equal to the principal amount plus the 1.5 percent deferred fee at maturity.

The senior credit facility and the subordinated demand credit facility are subject to the following financial covenants:

Financial covenant [1]	Requirement	As at September 30, 2014	Facility subject to financial covenant
Adjusted working capital ratio	> 1.0 : 1.0	**1.5**	Senior, Subordinated
Net debt to equity ratio	< 0.75 : 1.0	**0.6**	Subordinated
Net debt to funds from operations ratio December 31, 2014	< 2.8 : 1.0	**N/A**	Subordinated

(1) The financial covenant calculations refer to measures that are non-IFRS. Please see the definitions of non-IFRS measures at the beginning of this MD&A.

Delphi's calculation of its adjusted working capital ratio and net debt to funds from operations ratio are as follows:

Adjusted working capital ratio	As at September 30, 2014
Current assets	**40,094**
Undrawn portion of senior credit facility	**37,822**
Exclusion of the current fair value of financial instruments	**(81)**
	77,835
Current liabilities	**75,761**
Exclusion of the current portion of subordinated debt	**(20,146)**
Exclusion of the current fair value of financial instruments	**(2,698)**
	52,917
Adjusted working capital ratio	**1.5**

Net debt to funds from operations ratio	As at September 30, 2014
Long term debt	**132,178**
Subordinated debt	**20,146**
Current liabilities	**75,761**
Exclusion of the current portion of subordinated debt	**(20,146)**
Exclusion of the current fair value of financial instruments, net	**(2,617)**
Current assets	**(40,094)**
Net debt	**165,228**
Funds from operations for the three months ended September 30, 2014	**14,221**
Annualized (multiplied by four)	**56,884**
Net debt to funds from operations ratio	**2.9**

Delphi is in compliance with all covenants of its credit facilities as at September 30, 2014.

Contractual Obligations

Does the Company have any contractual obligations as of September 30, 2014 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. As noted above, the senior credit facility is based on a revolving term which is reviewed annually and converts to a 365 day non-revolving term facility if not renewed.

The future minimum commitments over the next five years ending on December 31 are as follows:

	2014	2015	2016	2017	2018	Thereafter
Gathering, processing and transmission	1,384	6,866	3,539	2,199	36	-
Office, equipment and software leases	541	1,835	1,393	957	-	-
Accounts payable and accrued liabilities (1)	50,707	-	-	-	-	-
Decommissioning obligations	204	-	-	-	-	41,168
Fair value of financial instruments	989	2,327	1,036	36	-	-
Restricted share units	250	1,759	485	59	-	-
Interest payments on subordinated debt	428	843	-	-	-	-
Long term debt	-	-	133,000	-	-	-
Subordinated debt (2)	20,500	-	-	-	-	-
Total	75,003	13,630	139,453	3,251	36	41,168

(1) Excludes the current portion of the restricted share units as they are disclosed separately on this table.

(2) The subordinated debt has a maturity date of December 31, 2014 and may be extended at the option of Delphi for an additional six months, subject to the Company being compliant with the financial covenants of the facility.

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 which are considered operating leases are charged to operating expenses or general and administrative expenses on a monthly basis according to the lease.

CRITICAL ACCOUNTING ESTIMATES

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

The reader is advised that the critical accounting estimates, judgments, policies and practices as described in the Company's Management's Discussion and Analysis for the year ended December 31, 2013 continue to be critical in determining Delphi's financial results.

The condensed consolidated interim financial statements have been prepared in conformity with IAS 34, Interim Financial Reporting, 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.

NEW ACCOUNTING STANDARDS

Did the Company adopt any new standards and are there any future accounting standards which the Company will have to comply with in the future?

IFRIC 21 - "Levies", establishes guidelines for the recognition and accounting treatment of a liability relating to a levy imposed by a government. This standard is effective for annual periods beginning on or after January 1, 2014 and was adopted by the Company effective January 1, 2014. The adoption of IFRIC 21 had no impact on the Company's consolidated financial statements.

Amendments to "Offsetting Financial Assets and Financial Liabilities" addressed within IAS 32 - "Financial Instruments: Presentation", which provides guidance regarding when it is appropriate and permissible for an entity to disclose offsetting financial assets and financial liabilities on a net basis. The amendments to this standard are effective for annual periods beginning on or after January 1, 2014 and were adopted by the Company effective January 1, 2014. The adoption of the IAS 32 amendments had no impact on the Company.

The IASB has issued IFRS 15, "Revenue from Contracts with Customers", which contains a single model that applies to contracts with customers and two approaches to recognizing revenue: at a point in time or over time. The model features a contract-based five-step analysis of transactions to determine whether, how much and when revenue is recognized. New estimates and judgmental thresholds have been introduced, which may affect the amount and/or timing of revenue recognized. The standard is effective for fiscal years ending on or after December 31, 2017 and is available for early adoption. The Company intends to adopt IFRS 15 in its financial statements for the annual period beginning on January 1, 2017. The extent of the impact of adoption of the standard has not yet been determined.

The IASB has issued IFRS 9, “Financial Instruments”, which is the result of the IASB’s project to replace IAS 39, “Financial Instruments: Recognition and Measurement”. The new standard replaces the current multiple classification and measurement models for financial assets and liabilities with a single model that has only two classification categories: amortized cost and fair value. The standard has an effective date of January 1, 2018. The Company is currently evaluating the impact of adopting this standard.

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 Company’s management, including its President and Chief Executive Officer and Senior Vice President, Finance and Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure. The President and Chief Executive Officer and Senior Vice President, Finance and Chief Financial Officer have designed, or caused to be designed under their supervision, internal controls over financial reporting to provide reasonable assurance regarding the reliability of the Company's financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles applicable to the Company.

The Company is required to disclose any change in the Company's internal control over financial reporting that occurred during the period beginning on July 1, 2014 and ended on September 30, 2014 that has materially affected, or is reasonably likely to materially affect, the Company's internal control over financial reporting. No material changes in the Company's internal control over financial reporting were identified during such period that has materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting.

It should be noted that a control system, including the Company's disclosure and internal controls and procedures, no matter how well conceived, can provide only reasonable, but not absolute, assurance that the objectives of the control system will be met and it should not be expected that the disclosure and internal controls and procedures will prevent all errors or fraud.

ADDITIONAL INFORMATION

Where is additional information about Delphi available?

Additional information about Delphi Energy 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.

Condensed Consolidated Statements of Financial Position

(thousands of dollars)	**September 30, 2014**	December 31, 2013
(unaudited)		
Assets		
Current assets		
Cash and cash equivalents	**14,081**	2,362
Accounts receivable	**23,772**	20,254
Prepaid expenses and deposits	**2,160**	4,605
Fair value of financial instruments (Note 5)	**81**	-
	40,094	27,221
Exploration and evaluation (Note 6)	**28,531**	24,666
Property, plant and equipment (Note 7)	**449,425**	399,793
Total assets	**518,050**	451,680
Liabilities		
Current liabilities		
Accounts payable and accrued liabilities	**52,713**	45,477
Decommissioning obligations	**204**	397
Fair value of financial instruments (Note 5)	**2,698**	4,794
Subordinated debt (Note 8)	**20,146**	19,807
	75,761	70,475
Restricted share units	**545**	629
Long term debt (Note 8)	**132,178**	99,880
Fair value of financial instruments (Note 5)	**1,690**	1,062
Decommissioning obligations	**41,168**	42,289
Deferred income taxes	**11,599**	5,119
Total liabilities	**262,941**	219,454
Shareholders' equity		
Share capital (Note 9)	**309,281**	305,027
Contributed surplus	**16,967**	16,663
Deficit	**(71,139)**	(89,464)
Total shareholders' equity	**255,109**	232,226
Total liabilities and shareholders' equity	**518,050**	451,680

Commitments (Note 10)
Subsequent event (Note 12)

See accompanying notes to the condensed consolidated interim financial statements.

DELPHI ENERGY CORP.

Condensed Consolidated Statements of Earnings and Comprehensive Income
For the three and nine months ended September 30,

	Three Months Ended September 30		Nine Months Ended September 30	
(thousands of dollars, except per share amounts)	**2014**	2013	**2014**	2013
(unaudited)				
Revenues				
Crude oil and natural gas sales	**35,117**	25,666	**128,336**	70,970
Royalties	**(5,021)**	(3,068)	**(20,233)**	(8,580)
	30,096	22,598	**108,103**	62,390
Realized (loss) gain on financial instruments (Note 5)	**(1,445)**	993	**(10,846)**	762
Unrealized gain on financial instruments (Note 5)	**4,727**	1,305	**1,549**	3,016
	33,378	24,896	**98,806**	66,168
Expenses				
Operating	**7,911**	7,556	**25,702**	18,088
Transportation	**3,363**	2,904	**10,278**	8,018
General and administrative	**1,440**	1,458	**4,576**	4,661
Share-based compensation	**631**	684	**4,088**	2,039
Gain on property dispositions (Note 7)	**(8,707)**	(42)	**(8,707)**	(3,137)
Loss on decommissioning	**-**	19	**389**	492
Depletion and depreciation (Note 7)	**10,236**	9,402	**30,919**	25,586
	14,874	21,981	**67,245**	55,747
Finance costs	**2,126**	1,944	**6,756**	4,928
Earnings before income taxes	**16,378**	971	**24,805**	5,493
Income taxes				
Deferred income taxes	**4,215**	(237)	**6,480**	1,020
Net earnings and comprehensive income	**12,163**	1,208	**18,325**	4,473
Net earnings per share (Note 9)				
Basic	**0.08**	0.01	**0.12**	0.03
Diluted	**0.08**	0.01	**0.11**	0.03

See accompanying notes to the condensed consolidated interim financial statements.

DELPHI ENERGY CORP.

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

	Nine Months Ended September 30,	
(thousands of dollars)	**2014**	2013
(unaudited)		
Share capital		
Common shares		
Balance, beginning of period	**305,027**	304,816
Issued on exercise of options	**2,902**	48
Transferred on exercise of options	**1,352**	24
Balance, end of period	**309,281**	304,888
Contributed surplus		
Balance, beginning of period	**16,663**	14,608
Share-based compensation	**1,656**	1,605
Transferred on exercise of options	**(1,352)**	(24)
Balance, end of period	**16,967**	16,189
Deficit		
Balance, beginning of period	**(89,464)**	(77,837)
Net earnings	**18,325**	4,473
Balance, end of period	**(71,139)**	(73,364)
Total shareholders' equity	**255,109**	247,713

See accompanying notes to the condensed consolidated interim financial statements.

DELPHI ENERGY CORP.

Condensed Consolidated Statements of Cash Flows
For the three and nine months ended September 30,

	Three Months Ended September 30,		Nine Months Ended September 30,	
(thousands of dollars)	**2014**	2013	**2014**	2013
(unaudited)				
Cash flow from (used in) operating activities				
Net earnings	**12,163**	1,208	**18,325**	4,473
Adjustments for:				
Depletion and depreciation	**10,236**	9,402	**30,919**	25,586
Accretion and finance charges	**409**	243	**1,217**	663
Share-based compensation	**632**	684	**2,216**	1,682
Gain on property dispositions	**(8,707)**	(42)	**(8,707)**	(3,137)
Loss on decommissioning	**-**	19	**389**	492
Unrealized gain on financial instruments	**(4,727)**	(1,305)	**(1,549)**	(3,016)
Deferred income taxes	**4,215**	(237)	**6,480**	1,020
Accretion of subordinated debt and long term debt	**477**	(735)	**49**	(524)
Decommissioning expenditures	**(445)**	(179)	**(1,074)**	(1,486)
Change in non-cash working capital (Note 11)	**(5,843)**	(148)	**2,770**	167
	8,410	8,910	**51,035**	25,920
Cash flow from (used in) financing activities				
Exercise of options	**324**	15	**2,902**	48
Finance lease obligation	**-**	-	**-**	(1,641)
Issue of subordinated debt	**-**	20,000	**-**	20,000
Increase in long term debt	**17,244**	(14,762)	**32,244**	14,679
Change in non-cash working capital (Note 11)	**-**	-	**-**	(212)
	17,568	5,253	**35,146**	32,874
Cash flow available for investing activities	**25,978**	14,163	**86,181**	58,794
Cash flow from (used in) investing activities				
Additions to exploration and evaluation	**(8,782)**	(11,520)	**(44,698)**	(12,645)
Acquisitions of exploration and evaluation	**(8,800)**	-	**(8,800)**	(12,135)
Additions to property, plant and equipment	**(20,568)**	(1,495)	**(39,301)**	(31,687)
Disposition of property, plant and equipment	**15,964**	42	**15,964**	3,319
Acquisition of property, plant and equipment	**-**	-	**-**	(1,529)
Change in non-cash working capital (Note 11)	**10,289**	6,168	**2,373**	3,241
	(11,897)	(6,805)	**(74,462)**	(51,436)
Increase in cash and cash equivalents	**14,081**	7,358	**11,719**	7,358
Cash and cash equivalents, beginning of period	**-**	-	**2,362**	-
Cash and cash equivalents, end of period	**14,081**	7,358	**14,081**	7,358
Cash interest paid	**1,970**	2,342	**4,228**	5,156

See accompanying notes to the condensed consolidated interim financial statements.

1) STRUCTURE OF DELPHI

Delphi Energy Corp. ("Delphi" or "the Company") is a publicly-traded company 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, from which in excess of 90 percent of the Company's production is obtained. The registered office of the Company is located at Suite 300, 500 – 4th Avenue S.W., Calgary, Alberta, T2P 2V6.

The condensed consolidated interim financial statements as at and for the three and nine months ended September 30, 2014 comprise the accounts of the Company, its wholly-owned subsidiary and a partnership.

2) BASIS OF PRESENTATION

(a) Statement of compliance and authorization

These condensed consolidated interim financial statements are unaudited and prepared in accordance with International Accounting Standard 34, "Interim Financial Reporting" as issued by the International Accounting Standards Board, and do not include all of the information and disclosures normally provided in annual financial statements and should be read in conjunction with the Company's consolidated financial statements for the year ended December 31, 2013.

These condensed consolidated interim financial statements were approved and authorized for issuance by the Board of Directors on November 10, 2014.

(b) Basis of measurement and functional currency

The condensed consolidated interim financial statements have been prepared on a going concern basis, using historical costs, except for derivative financial instruments and liabilities for cash-settled share-based payment arrangements which are measured at fair value. The financial statements are presented in Canadian dollars, the Company's functional currency and rounded to the nearest thousand (unless stated otherwise).

(c) Use of estimates and judgments

The preparation of the condensed consolidated interim 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 in the condensed consolidated interim financial statements and accompanying notes. By their nature, these estimates are subject to measurement uncertainty and the effect on the financial statements of changes in such estimates in future periods could be material. Actual results may differ from these estimates. Estimates and judgments are continuously evaluated and are based on management's experience and other factors, including expectations of future events that are believed to be reasonable under the circumstances. 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 critical judgments that management has made in the process of applying Delphi's accounting policies and that have the most significant effect on the amounts recognized were the same as those applied to the consolidated financial statements as at and for the year ended December 31, 2013 with the exception of judgments and estimates related to business combinations. The determination of fair value of the acquired assets and liabilities through a business combination requires management to make assumptions and estimates about future events. The assumptions and estimates with respect to determining the fair value of property, plant and equipment, and exploration and evaluation assets acquired generally require the most judgment and include estimates of reserves acquired, forecast benchmark commodity prices and discount rates. Changes in any of the assumptions or estimates used in determining the fair value of the acquired assets and liabilities could impact the amounts assigned to assets, liabilities in the purchase price allocation and any resulting gain or goodwill. Future net earnings can be affected as a result in future depletion, depreciation and accretion and asset impairments.

3) SIGNIFICANT ACCOUNTING POLICIES

The accounting policies applied by the Company in these condensed consolidated interim financial statements are the same as those applied by the Company in its consolidated financial statements as at and for the year ended December 31, 2013 with the exception of the following:

Business Combinations

Business combinations are accounted for using the acquisition method. The identifiable assets acquired and liabilities and contingent liabilities assumed are measured at their fair values at the acquisition date. The cost of an acquisition is measured as the aggregate consideration transferred, measured at the acquisition date fair value. If the cost of the acquisition is less than the fair value of the net assets acquired, the difference is recognized immediately in net earnings. If the cost of the acquisition is more than the fair value of the net assets acquired, the difference is recognized on the balance sheet as goodwill. Acquisition costs incurred are expensed.

The following are new and amended standards which have been adopted with an effective date of January 1, 2014 and have been applied retrospectively:

IFRIC 21 - "Levies", which establishes guidelines for the recognition and accounting treatment of a liability relating to a levy imposed by a government. The adoption of IFRIC 21 had no impact on the Company's consolidated financial statements.

IAS 32, "Financial Instruments: Presentation", which clarifies the requirements for offsetting financial assets and liabilities. The amendments clarify when an entity has a legally enforceable right to offset and certain other requirements that are necessary to present a net financial asset or liability. There was no impact to the Company on the adoption of the amendments to IAS 32.

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. IFRS establishes a fair value hierarchy that prioritizes the inputs to valuation techniques used to measure fair value. The three levels of the fair value hierarchy are described as follows:

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.

Fair values have been determined for measurement and/or disclosure purposes based on the following methods:

(a) Cash and cash equivalents, accounts receivable and accounts payable and accrued liabilities:

The fair value of cash and cash equivalents, accounts receivable and accounts payable and accrued liabilities approximate their carrying value due to their short term to maturity.

(b) Subordinated debt and long term debt:

The Company's subordinated debt is measured at level 2 of the fair value hierarchy for disclosure purposes. The subordinated debt has a fair value of $19.7 million based on future cash flows associated with the facility discounted at current market rates of interest. 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 is indicative of the Company's current credit premium.

(c) Restricted share units:

The restricted share unit liability is measured at level 2 of the fair value hierarchy. The fair value is based on the Company's closing share price on the last business day immediately preceding the date of the consolidated statement of financial position.

(d) Derivatives:

Delphi's interest and commodity contracts are measured at level 2 of the fair value hierarchy. The fair value of commodity contracts is determined by discounting the remaining contracted petroleum and natural gas volumes by the difference between the contracted price and published forward price curves as at the consolidated financial position date. The fair value of interest rate swap contracts is determined by discounting the net future cash flows based on the fixed and variable rates associated with the notional amounts.

5) FINANCIAL RISK MANAGEMENT

The Company is exposed to market, credit and liquidity risks from its use of financial instruments. There have not been any changes to the Company's exposure to each of the above risks and the Company's policies and processes for measuring and managing these risks since December 31, 2013.

As at September 30, 2014, Delphi had the following derivative financial commodity risk management contracts outstanding:

Financial Contracts

Time Period	Type of Contract	Quantity Contracted	Price Floor ($/unit)		Price Ceiling ($/unit)	
April 2013 – April 2015	Natural Gas – fixed	3,000 GJ/d	$3.54	Cdn	$3.54	Cdn
April 2013 – December 2015	Natural Gas – fixed	3,000 GJ/d	$3.27	Cdn	$3.27	Cdn
April 2013 – December 2016	Natural Gas – fixed	3,000 GJ/d	$3.40	Cdn	$3.40	Cdn
June 2013 – December 2016	Natural Gas – fixed	6,000 GJ/d	$3.45	Cdn	$3.45	Cdn
August 2013 – October 2014	Natural Gas – fixed	3,000 mmbtu/d	$3.71	U.S.	$3.71	U.S.
January 2014 – October 2014	Natural Gas – fixed	2,500 GJ/d	$3.65	Cdn	$3.65	Cdn
April 2014 – October 2014	Natural Gas – fixed	5,000 GJ/d	$3.40	Cdn	$3.40	Cdn
April 2014 – October 2014	Natural Gas – fixed	5,000 GJ/d	$3.25	Cdn	$3.25	Cdn
January 2015 – December 2015	Natural Gas – fixed	2,500 GJ/d	$3.67	Cdn	$3.67	Cdn
January 2015 – December 2015	Natural Gas – fixed	5,000 GJ/d	$3.69	Cdn	$3.69	Cdn
April 2015 – October 2015	Natural Gas – fixed	2,500 GJ/d	$3.49	Cdn	$3.49	Cdn
April 2015 – October 2015	Natural Gas – fixed	2,500 GJ/d	$3.62	Cdn	$3.62	Cdn
January 2016 – December 2016	Natural Gas – fixed	2,500 GJ/d	$3.69	Cdn	$3.69	Cdn
January 2017 – December 2017	Natural Gas – fixed	2,500 GJ/d	$3.75	Cdn	$3.75	Cdn
January 2014 – December 2014	Crude Oil – call option	600 bbls/d		-	$90.00	U.S.
January 2014 – December 2014	Crude Oil – put option (1)	1,000 bbls/d	$110.15	Cdn		-
January 2015 – December 2015	Crude Oil – put option (1)	250 bbls/d	$101.00	Cdn		-
January 2015 – December 2015	Crude Oil – put option (1)	250 bbls/d	$100.85	Cdn		-

(2) The put contract for 1,000 bbls/d from January 2014 to December 2014 has a deferred cost of $4.01 per barrel. The put contracts for 250 bbls/d from January 2015 to December 2015 have a deferred cost of $6.00 per barrel and $5.85 per barrel, respectively.

For the month of October 2014, the Company has a physical contract to deliver 7,500 GJ/d at a fixed price of $3.97 Cdn per gigajoule.

Subsequent to September 30, 2014, Delphi entered into the following contracts:

Time Period	Type of Contract	Quantity Contracted	Price ($/unit)	
January 2015 – December 2015	Natural Gas – fixed, financial	2,500 GJ/d	$3.80	Cdn
November 2014	Natural Gas – fixed, physical	10,000 GJ/d	$3.52	Cdn
December 2014	Natural Gas – fixed, physical	5,000 GJ/d	$4.10	Cdn

In addition to commodity risk management contracts, the Company has an interest rate swap transaction on borrowings through bankers' acceptances in the amount of $20.0 million maturing on February 28, 2015. The swap transaction has a fixed interest rate of 1.25 percent.

For the three and nine months ended September 30, 2014, the derivative commodity contracts resulted in realized losses of $1.4 million and $10.8 million, respectively, that have been included in the consolidated statement of earnings as a realized loss on financial instruments.

The fair value of the risk management contracts outstanding as at September 30, 2014 is estimated to be a current asset of $81 thousand, a current liability of $2.7 million and a long term liability of $1.7 million (December 31, 2013 – current liability of $4.8 million and a long term liability of $1.1 million). For the three and nine months ended September 30, 2014, Delphi recorded an unrealized gain on its risk management contracts of $4.7 million and $1.5 million, respectively. The unrealized gain recognized for the three and nine months ended September 30, 2014 is the difference between the fair values of the risk management contracts outstanding as at September 30, 2014 and the fair values as at June 30, 2014 and December 31, 2014, respectively.

As at September 30, 2014, if the future strip prices for crude oil were $1.00 per barrel higher with all other variables held constant, the net earnings for the three and nine months ended September 30, 2014 would have decreased by $0.2 million. As at September 30, 2014, if the future strip prices for natural gas were $0.10 per gigajoule higher with all other variables held constant, the net earnings for the three and nine months ended September 30, 2014 would have decreased by $1.2 million.

Offsetting financial assets and financial liabilities

As at September 30, 2014 the following derivative financial assets and financial liabilities were offset on the consolidated statement of financial position:

	Gross Amounts of Recognized Financial Liabilities	**Gross Amounts of Recognized Financial Assets Offset**	**Net Amounts of Financial Assets (Liabilities) Recognized**
Risk management contracts			
Current asset	(1,593)	1,674	81
Current liability	(2,882)	184	(2,698)
Long term liability	(2,165)	475	(1,690)
Net asset (liability)	**(6,640)**	**2,333**	**(4,307)**

6) EXPLORATION AND EVALUATION ASSETS

	Total
Balance as at December 31, 2012	12,406
Additions	16,902
Acquisitions	12,135
Expense	(315)
Transfer to oil and gas properties	(16,462)
Balance as at December 31, 2013	24,666
Additions	44,698
Acquisitions	8,800
Transfer to oil and gas properties	(49,633)
Balance as at September 30, 2014	**28,531**

Exploration and evaluation assets consist of the Company's exploration projects which are pending the determination of proven and probable reserves.

During the first nine months of 2014, Delphi added $44.7 million of exploration and evaluation expenditures related to developing the Montney formation at Bigstone. During the third quarter of 2014, Delphi acquired eight gross (3.5 net) sections of Montney rights at East Bigstone for a purchase price of $8.8 million after closing adjustments. During the first nine months of 2014, $49.6 million of exploration and evaluation assets were transferred to property, plant and equipment following the successful discovery of proven and probable reserves.

During 2013, Delphi added $16.9 million of exploration and evaluation expenditures related to developing the Montney formation at Bigstone. During the first quarter of 2013, Delphi acquired 30 gross (26.8 net) sections of Montney mineral rights for $13.7 million. Certain of the sections acquired were assigned reserves due to their proximity to existing Delphi producing wells. The sections that were assigned reserves were included in crude oil and natural gas properties. For the year ended December 31, 2013, $16.5 million of exploration and evaluation assets were transferred to property, plant and equipment following the successful discovery of proven and probable reserves. During 2013, the Company expensed $0.3 million of exploration and evaluation assets as management does not intend to extend the leases of certain lands in the Company's North East British Columbia ("NEBC") cash generating unit ("CGU").

7) PROPERTY, PLANT AND EQUIPMENT

Cost	**Crude oil and natural gas properties**	**Production equipment**	**Other assets**	**Total**
Balance as at December 31, 2012	534,447	49,233	860	584,540
Additions	54,412	1,704	25	56,141
Acquisitions	1,529	-	-	1,529
Decommissioning obligations	7,763	(625)	-	7,138
Dispositions	(419)	-	-	(419)
Transfer from exploration and evaluation assets	16,462	-	-	16,462
Balance as at December 31, 2013	614,194	50,312	885	665,391
Additions	20,352	20,459	147	40,958
Decommissioning obligations	(1,568)	66	-	(1,502)
Dispositions	(24,426)	(1,183)	-	(25,609)
Transfer from exploration and evaluation assets	49,633	-	-	49,633
Balance as at September 30, 2014	**658,185**	**69,654**	**1,032**	**728,871**

Accumulated depletion and depreciation	**Crude oil and natural gas properties**	**Production equipment**	**Other assets**	**Total**
Balance as at December 31, 2012	(202,704)	(11,387)	(381)	(214,472)
Depletion and depreciation	(34,876)	(1,021)	(121)	(36,018)
Dispositions	192	-	-	192
Impairment losses	(14,074)	(1,226)	-	(15,300)
Balance as at December 31, 2013	(251,462)	(13,634)	(502)	(265,598)
Depletion and depreciation	(29,877)	(946)	(96)	(30,919)
Dispositions	16,522	549	-	17,071
Balance as at September 30, 2014	**(264,817)**	**(14,031)**	**(598)**	**(279,446)**
Net book value as at December 31, 2013	362,732	36,678	383	399,793
Net book value as at September 30, 2014	**393,368**	**55,623**	**434**	**449,425**

For the three months ended September 30, 2014, Delphi has included $437.9 million (September 30, 2013: $277.6 million) for future development costs and excluded $2.0 million (September 30, 2013: $2.0 million) for estimated salvage to its costs subject to depletion and depreciation.

For the nine months ended September 30, 2014, Delphi capitalized $2.2 million (December 31, 2013: $2.0 million) of general and administrative expenses and $0.6 million (December 31, 2013: $1.3 million) of share-based compensation expense directly related to exploration and development activities.

During the third quarter of 2014, Delphi received proceeds of $16.0 million for the sale of certain interests in its Hythe property with a net book value of $8.5 million, including decommissioning liabilities of $2.8 million, resulting in a gain of $7.5 million. During the third quarter of 2014, Delphi exchanged assets with a net book value of $69 thousand for assets with a fair value of $1.3 million, resulting in a gain of $1.2 million.

For the year ended December 31, 2013, the Company recognized $15.3 million of impairments relating to its Hythe, Berland River, Miscellaneous Alberta and NEBC CGUs. The impairments were based on the difference between the period end carrying value of the CGU's and the recoverable amount. The recoverable amounts were determined using a fair value less costs to sell methodology with the expected future cash flows based on proved and probable reserves using pre-tax discount rates of twelve to 20 percent.

8) LONG TERM DEBT AND SUBORDINATED DEBT

	September 30, 2014	December 31, 2013
Senior Credit Facility		
Prime-based loans	**33,000**	2,000
Bankers' acceptances, net of discount	**99,178**	97,880
	132,178	99,880
Subordinated debt, net of finance costs	**20,146**	19,807
Total	**152,324**	119,687

The annual review of the Company's senior extendible revolving term credit facility was conducted during the first quarter of 2014 resulting in a $30.0 million increase in the borrowing base to $170.0 million.

The Company's senior extendible revolving term credit facility with a syndicate of Canadian chartered banks is subject to the banks' semi-annual review 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 25, 2015 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 25, 2016. 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 U.S. 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 net debt to annualized quarterly funds from operations ratio: from a minimum of the bank's prime rate or U.S. base rate plus 1.00 percent to a maximum of the bank's prime rate or U.S. base rate plus 2.50 percent or from a minimum of bankers' acceptances rate plus a stamping fee of 2.00 percent to a maximum of bankers' acceptances rate plus a stamping fee of 3.50 percent.

The syndicated credit facility is secured by a $300.0 million demand floating charge debenture and a general security agreement over all assets of the Company.

A semi-annual review of the Company's $170.0 million extendible revolving term credit facility will be conducted during the fourth quarter of 2014. The borrowing base of the facilities will be based on the lenders' evaluation of the Company's petroleum and natural gas reserves and commodity prices.

During the third quarter of 2013, Delphi obtained a $20.0 million subordinated demand credit facility with a Canadian energy and resource lender. The debt is secured by the Company's assets and is subordinate to the Company's senior credit facility. The debt has a maturity date of December 31, 2014 and may be extended at the option of Delphi for an additional six months, subject to the Company being compliant with the financial covenants of the facility.

The subordinated debt has an annual coupon rate of 8.5 percent with interest payable monthly. A deferred fee of 1.5 percent of the facility is due upon maturity. The subordinated debt of $20.0 million, net of $0.4 million of financing costs is accreted using the effective interest rate method such that the carrying amount of the subordinated debt will be equal to the principal amount plus the 1.5 percent deferred fee at maturity.

The senior credit facility and the subordinated demand credit facility are subject to the following financial covenants:

Financial covenant	**Requirement**	**As at September 30, 2014**	**Facility subject to financial covenant**
Adjusted working capital ratio	> 1.0 : 1.0	**1.5**	Senior, Subordinated
Net debt to equity ratio	< 0.75 : 1.0	**0.6**	Subordinated
Net debt to funds from operations ratio December 31, 2014	< 2.8 : 1.0	**N/A**	Subordinated

For the purpose of the financial covenants, the following definitions are applicable:

Adjusted working capital ratio

Current assets include the undrawn portion of the senior credit facility and exclude the current portion of the fair value of financial instruments. Current liabilities exclude the current portion of long term debt and subordinated debt and the current portion of the fair value of financial instruments.

Net debt to equity ratio

Net debt is defined as long term debt and subordinated debt plus (minus) the working capital deficit (surplus) excluding the current portion of the fair value of financial instruments. Equity is equivalent to shareholders' equity.

Net debt to funds from operations ratio

Net debt is defined as long term debt and subordinated debt plus (minus) the working capital deficit (surplus) excluding the current portion of the fair value of financial instruments. Funds from operations is defined as cash flow from operating activities before accretion of long term and subordinated debt, decommissioning expenditures and changes in non-cash working capital from operating activities. Delphi's most recently completed quarter's funds from operations is annualized (multiplied by four) for the calculation of this ratio.

Delphi is in compliance with all covenants as at September 30, 2014.

9) SHARE CAPITAL

Delphi is authorized to issue an unlimited number of common shares. All shares are issued as fully paid and non-assessable and have no par value. The holders of common shares are entitled to receive dividends as declared by the Company and are also entitled to one vote per share.

(a) Issued and outstanding	**September 30, 2014**		December 31, 2013	
	Outstanding shares (000's)	**Amount**	Outstanding shares (000's)	Amount
Balance, beginning of period	**153,254**	**305,027**	153,049	304,816
Issued on exercise of stock options	**2,187**	**2,902**	205	141
Transferred on exercise of options	**-**	**1,352**	-	70
Balance, end of period	**155,441**	**309,281**	153,254	305,027

For the nine months ended September 30, 2014, a total of 2.2 million stock options were exercised. The weighted average share trading price of the Company's common shares at the dates of exercise ranged from $1.88 to $4.51.

During the nine months ended September 30, 2014, Delphi granted 2.2 million stock options to employees and consultants with a weighted average fair value of $1.20 per option. As at September 30, 2014, 12.8 million stock options were outstanding with a weighted average exercise price of $1.92 per option.

During the nine months ended September 30, 2014, Delphi granted 0.5 million restricted share units to employees and consultants. During the nine months ended September 30, 2014, 0.6 million restricted share units vested resulting in a cash expense, net of capitalization, of $1.9 million. As at September 30, 2014, 1.4 million restricted share units were outstanding.

(b) Net earnings per share

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	**2014**	2013
Weighted average common shares - basic	**155,285**	153,100	**154,633**	153,090
Dilutive effect of share options outstanding	**6,165**	943	**5,382**	417
Weighted average common shares - diluted	**161,450**	154,043	**160,015**	153,507

For the three and nine months ended September 30, 2014, a total of 6.6 million and 7.4 million stock options, respectively, were excluded from the calculation as they were anti-dilutive. For the three and nine months ended September 30, 2013, a total of 12.1 million and 12.7 million stock options, respectively, were excluded from the calculations as they were anti-dilutive.

10) COMMITMENTS

Delphi is committed to future minimum payments for natural gas gathering, processing and transmission, operating leases on compression equipment and office space. Payments required under these commitments for each for the next five years ending on December 31 are as follows:

	2014	2015	2016	2017	2018
Gathering, processing and transmission	1,384	6,866	3,539	2,199	36
Office, equipment and software leases	541	1,835	1,393	957	-
Total	1,925	8,701	4,932	3,156	36

11) SUPPLEMENTAL CASH FLOW INFORMATION

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

	Three Months Ended September 30,		Nine Months Ended September 30	
	2014	2013	**2014**	2013
Source (use) of cash				
Accounts receivable	**(3,428)**	1,917	**(3,518)**	(3,670)
Prepaid expenses and deposits	**886**	761	**2,445**	491
Outstanding cheques	**(2,012)**	(2,517)	**-**	(883)
Accounts payable and accrued liabilities	**9,000**	5,859	**6,216**	7,258
Total change in non-cash working capital	**4,446**	6,020	**5,143**	3,196
Relating to:				
Operating activities	**(5,843)**	(148)	**2,770**	167
Financing activities	**-**	-	**-**	(212)
Investing activities	**10,289**	6,168	**2,373**	3,241
	4,446	6,020	**5,143**	3,196

12) SUBSEQUENT EVENT

On October 1, 2014, Delphi acquired production, undeveloped land and a natural gas processing facility in West Bigstone for a cash purchase price of $8.8 million after closing adjustments. The acquisition complements Delphi's existing West Bigstone assets and provides Delphi with direct-to-sales infrastructure for future Montney development at West Bigstone.

In accordance with IFRS, a property acquisition is accounted for as a business combination when certain criteria are met, such as the acquisition of inputs and processes to convert those inputs into beneficial outputs. Delphi assessed the property acquisition and determined that it constitutes a business combination under IFRS.

The estimated fair value of the property, plant and equipment acquired was determined using internal estimates. The decommissioning liabilities assumed were determined using the timing and estimated costs associated with the abandonment, restoration and reclamation of the wells and facility acquired.

A summary of the acquired property is provided below:

Estimated fair value of acquired properties [1]	
Oil and natural gas properties	10,212
Exploration and evaluation assets	135
Property, plant and equipment	1,070
Decommissioning liabilities	(2,568)
Total	**8,849**
Cash consideration	**8,849**

(1) The fair value of the acquired properties are based on preliminary internal estimates.

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Delphi Energy Corp.

Tony Angelidis
Senior Vice President Exploration
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Lamont C. Tolley (1) (2)
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(1) Member of the Audit Committee
(2) Member of the Reserves Committee
(3) Member of the Corporate Governance and Compensation Committee

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INDEPENDENT ENGINEERS

GLJ Petroleum Consultants Ltd.

STOCK EXCHANGE LISTING

Toronto Stock Exchange – DEE

TRANSFER AGENT

Olympia Trust Company

ABBREVIATIONS

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

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