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 twelve months ended December 31, 2014 and 2013 and should be read in conjunction with the audited consolidated financial statements and accompanying notes for the years ended December 31, 2014 and 2013. The audited consolidated financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB"). The reporting currency is the Canadian dollar. The discussion and analysis has been prepared as of March 17, 2015.

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.

2014 ACCOMPLISHMENTS

What were the highlights of Delphi's operational and financial results in 2014?

In 2014, the Company achieved the following:

- Produced an average of 10,549 barrels of oil equivalent per day ("boe/d") in 2014, up 28 percent from the average of 8,241 boe/d in 2013. Average production in the fourth quarter of 2014 increased 34 percent to 12,035 boe/d compared to the fourth quarter of 2013;

- Cash netbacks per barrel of oil equivalent ("boe") increased by 30 percent over the comparative year resulting in funds from operations of $65.2 million, a 67 percent increase over 2013;

- Increased average field condensate production in 2014 by 106 percent to 1,421 barrels per day ("bbls/d") in comparison to 2013 and increased average field condensate production in the fourth quarter of 2014 by 71 percent to 1,639 bbls/d compared to the same period in 2013;

- Expanded the capacity of its 100 percent owned compression and dehydration facility in East Bigstone from 30.0 million cubic feet per day ("mmcf/d") to 45.0 mmcf/d and doubled the field condensate storage to 6,000 barrels;

- Completed pipeline connections to deliver its Montney production at Bigstone to the SemCams K3 processing facility;

- Successfully drilled eight wells (7.6 net) as part of the Company's capital program and completed, tied-in and brought on production nine gross (8.5 net) Montney wells in East Bigstone;

- Increased Montney production from 3,884 boe/d in the fourth quarter of 2013 to 7,743 boe/d in the fourth quarter of 2014, an increase of 99 percent;

- Maintained Montney natural gas liquids ("NGL") and field condensate yields at 95 barrels per million cubic feet ("bbls/mmcf") in 2014. Field and plant condensate yield was 67 bbls/mmcf or 70 percent of the total 95 bbls/mmcf;

- Added 21.5 gross (14.8 net) sections of Montney rights at Bigstone, including the acquisition of eight gross (3.5 net) sections of Montney rights for a purchase price of $8.8 million after closing adjustments;

- Acquired 430 boe/d of production, undeveloped land (19.3 net sections) and a natural gas processing facility in West Bigstone for a purchase price of $8.9 million after closing adjustments;

- Closed the sale of certain interests from its Hythe property for net proceeds of $15.8 million after closing adjustments;

- Constructed a nine mmcf/d compression/dehydration facility and gathering system in the southern part of East Bigstone to handle Delphi's Montney production in the area;

- Executed a three year natural gas processing agreement with SemCams ULC for transportation to and processing of raw natural gas at the SemCams K3 plant from the Company's condensate rich Montney play in the Bigstone area of Alberta;

- Entered into an agreement with Alliance Pipeline Ltd. for full path service to deliver up to 62.8 mmcf/d of natural gas volumes by the end of 2017 into the Chicago gas market;

- Increased the borrowing base of the senior credit facilities by a total of $50.0 million to $190.0 million upon completion of the lenders' annual and semi-annual reviews during the year; and

- Renewed its $20.0 million subordinated credit facility to extend the maturity date to June 30, 2016.

Funds from operations in 2014 were $65.2 million or $0.42 per basic share ($0.41 per diluted share), compared to $39.1 million or $0.26 per basic share ($0.25 per diluted share) in 2013. The increase in funds from operations from 2013 to 2014 is primarily due to an improvement in realized prices in combination with an increase in field condensate, natural gas and natural gas liquids production associated with the Montney development program at East Bigstone.

2014 OPERATIONAL AND FINANCIAL RESULTS

LIQUIDITY AND CAPITAL RESOURCES

Sources and Uses of Funds

	Three Months Ended December 31, 2014	Twelve Months Ended December 31, 2014
Sources:		
Cash and cash equivalents	**10,951**	**-**
Funds from operations	**15,869**	**65,159**
Disposition of petroleum and natural gas properties	**651**	**16,615**
Exercise of stock options	**45**	**2,947**
	27,516	**84,721**
Uses:		
Cash and cash equivalents	**-**	**768**
Capital expenditures	**16,852**	**100,851**
Acquisition of petroleum and natural gas properties	**8,858**	**17,658**
Accretion of subordinated and long term debt	**381**	**332**
Expenditures on decommissioning	**86**	**1,160**
Changes in non-cash working capital	**6,173**	**1,030**
	32,350	**121,799**
Change in long term debt	**4,834**	**37,078**

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 (deflationary) pressures on service costs. Volatility in crude oil and natural gas prices has resulted in a challenging environment for the energy sector. In response to this volatility and to preserve financial flexibility, Delphi is taking a conservative approach to its capital spending plans in 2015. Delphi will continue to monitor commodity prices and service cost reductions in order to manage its 2015 capital program. In addition, Delphi has an active commodity price risk management program in order to reduce its exposure to fluctuations in commodity prices and protect its future cash flows.

How much debt was outstanding on December 31, 2014?

At December 31, 2014, the Company had $99.3 million outstanding in the form of bankers' acceptances, $38.0 million drawn under Canadian-based prime loans, $19.5 million in subordinated debt and a working capital deficiency of $16.9 million for net debt of $173.7 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 related covenants and when is the next scheduled review of the borrowing base?

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 was increased by $30.0 million to $170.0 million in March 2014 and a further $20.0 million increase to $190.0 million in December 2014. It 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 would be 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 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.

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 subordinated debt had an original maturity date of December 31, 2014 but was extended during the fourth quarter of 2014 to a maturity date of June 30, 2016.

The subordinated debt has been classified as a current liability as it is secured by a $25.0 million demand floating charge debenture. The Company believes the lender has no intention of demanding repayment of the subordinated debt before the maturity date of June 30, 2016. At maturity, the Company expects to repay the subordinated debt through borrowings under its senior credit facility.

The subordinated debt had an annual coupon rate of 8.5 percent with interest payable monthly. The renewed terms of the subordinated debt has an annual coupon rate of 10.5 percent with interest payable monthly. A deferred fee of 1.5 percent of the facility is due upon maturity.

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

Financial covenant [(1)]	Requirement	As at December 31, 2014	Facility subject to financial covenant
Adjusted working capital ratio	≥ 1.0 : 1.0	1.9	Senior, Subordinated
Net debt to equity ratio [(2)]	< 1.0 : 1.0	0.8	Subordinated
Net debt to funds from operations ratio	≤ 2.8 : 1.0	2.7	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.

(2) Under the renewed terms of the subordinated debt, the requirement for this ratio was increased to be less than 1.0 : 1.0 from 0.75 : 1.0.

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 December 31, 2014
Current assets	41,620
Exclusion of the current fair value of financial instruments	(16,873)
Undrawn portion of senior credit facility	52,719
	77,466
Current liabilities	61,121
Exclusion of the current portion of subordinated debt	(19,547)
	41,574
Adjusted working capital ratio	1.9

Net debt to funds from operations ratio	As at December 31, 2014
Long term debt	137,281
Subordinated debt	19,547
Current liabilities	61,121
Exclusion of the current portion of subordinated debt	(19,547)
Current assets	(41,620)
Exclusion of the current fair value of financial instruments	16,873
Net debt	173,655
Funds from operations for the three months ended December 31, 2014	15,869
Annualized (multiplied by four)	63,476
Net debt to funds from operations ratio	2.7

Delphi is in compliance with all covenants of its credit facilities as at December 31, 2014.

The annual review of the Company's $190.0 million extendible revolving term credit facility will be conducted prior to May 25, 2015. The borrowing base of the facilities will be based on the lenders' evaluation of the Company's petroleum and natural gas reserves at that time and commodity prices. A decrease in the borrowing base could result in a reduction to the credit facility, which may require a repayment to the lenders.

The Company's subordinated debt is classified as a current liability, as it is secured by a $25.0 million demand floating charge debenture, and has a covenant of net debt to funds from operations ratio of not greater than 2.8:1. As a result of the current low commodity price environment, Delphi has been in discussions with its subordinated debt lenders to ensure its financial flexibility.

Share Capital

How many common shares and stock options are currently outstanding?

As at March 17, 2015, the Company had 155.5 million common shares outstanding and 12.8 million share options outstanding. The share 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 twelve months ended December 31, 2014:

	Three Months Ended December 31, 2014	Twelve Months Ended December 31, 2014
Weighted Average Common Shares		
Basic	**155,453**	**154,839**
Diluted	**157,953**	**159,492**
Trading Statistics (1)		
High	**3.33**	**4.53**
Low	**1.25**	**1.25**
Average daily volume	**1,354,307**	**985,683**

(1) Trading statistics based on closing price

BUSINESS ENVIRONMENT

What external factors of the business environment did the Company have to contend with in 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 December 31			Twelve Months Ended December 31		
	2014	2013	% Change	**2014**	2013	% Change
Natural Gas						
NYMEX (US $/mmbtu)	**3.86**	3.86	-	**4.27**	3.72	15
AECO (CDN $/mcf)	**3.60**	3.53	2	**4.48**	3.17	41
Crude Oil						
West Texas Intermediate (US $/bbl)	**73.12**	97.50	(25)	**92.92**	98.00	(5)
Edmonton Light (CDN $/bbl)	**75.63**	86.40	(12)	**94.38**	93.00	1
Foreign Exchange						
Canadian to U.S. dollar	**0.88**	0.95	(7)	**0.91**	0.97	(6)
U.S. to Canadian dollar	**1.14**	1.05	9	**1.10**	1.03	7

Natural Gas

In the first half of 2014, the level of natural gas storage decreased to levels below 2013 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 unexpected and significant 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 rebounded in the second half of 2014 due to record production levels and lower than prior year demand due to a mild summer and an average heating demand start to the winter. For the three and twelve months ended December 31, 2014, AECO increased two percent and 41 percent, respectively.

Natural Gas Liquids

Natural gas liquids include ethane, propane, butane, pentane and plant condensate 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. 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

Crude oil prices in the first seven months of 2014 reached their highest levels since the financial collapse of 2008 with WTI averaging over U.S. $105.00 in the month of July. Horizontal drilling and multi-stage fracture stimulation technology combined with higher oil prices over the past several years resulted in increasing capital expenditure programs directed at tight oil in the United States shale plays, primarily the Bakken in North Dakota and the Eagle Ford and Permian Basin in Texas. U.S. field production grew from five million barrels per day in 2008 to 8.7 million barrels per day in 2014. Global supply/demand fundamentals for crude oil moved into an oversupply position with OPEC, particularly Saudi Arabia, stating in November that it would not be the swing producer to balance the global crude oil market this time. Since that announcement, crude oil prices have fallen by over 50 percent to a level for WTI of U.S. $50 per barrel over the past month. Opinions still vary as to whether or not a bottom has been set for crude oil prices and as to the pace of price recovery going forward.

WTI averaged U.S. $73.12 per barrel in the fourth quarter of 2014 and U.S. $92.92 per barrel for the year ended December 31, 2014, a decrease of 25 percent and five percent over the respective comparative periods in 2013. Canadian prices experienced a narrowing basis differential as well as a decline in the Canadian to U.S. dollar exchange rate. Edmonton Light averaged $75.63 per barrel in the fourth quarter of 2014, down 12 percent compared to the same period in 2013, and $94.38 per barrel for the year ended December 31, 2014, up one percent from 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 $0.87 in December 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 and twelve months ended December 31, 2014 were $0.88 and $0.91, respectively.

DRILLING OPERATIONS

How active was Delphi in its drilling program in 2014?

Delphi's successful drilling program in 2014 was focused on the Bigstone Montney formation, drilling eight gross (7.6 net) wells, including two gross (1.9 net) wells which were drilled during the fourth quarter of 2014. In comparison, Delphi was successful in drilling six gross (5.7 net) wells in 2013 which were also focused on the Bigstone Montney formation.

Delphi has been utilizing the same drilling rig, equipment service providers and drilling crew since the start of its 2013 Montney drilling program. This has resulted in drilling times for its two mile horizontal extended laterals being reduced to approximately 30 days on a consistent basis. In 2014, the Company was able to take advantage of a slow thaw and pad drilling to drill two wells over spring break-up, increasing the wells drilled to eight from six, utilizing one drilling rig.

	Three Months Ended December 31, 2014		Twelve Months Ended December 31, 2014	
	Gross	**Net**	**Gross**	**Net**
Liquids-rich natural gas	**2.0**	**1.9**	**8.0**	**7.6**
Success rate (%)	**100**	**100**	**100**	**100**

CAPITAL INVESTED

How much capital was invested by the Company in 2014 and where were the capital expenditures incurred?

During the fourth quarter of 2014, Delphi invested $16.9 million of capital expenditures and $8.9 million on the acquisition of developed properties. The acquisition was partially funded by proceeds on disposition from the third quarter of 2014. During the fourth quarter of 2014, Delphi directed 96 percent of its capital invested toward the drilling of two gross (1.9 net) wells and completion operations and the equipping of one net well. One well was brought on production in the middle of the quarter and the other well was brought on during the first quarter of 2015. During the fourth quarter of 2014, the Company disposed of a minor interest in a section of non-Montney undeveloped land for proceeds of $0.7 million.

During 2014, Delphi invested $100.9 million of capital expenditures, with approximately $74.3 million, or 74 percent, being directed toward the production development of its Montney formation at East Bigstone. Delphi drilled eight gross (7.6 net) wells and completed fracture stimulation operations and equipping on nine gross (8.5 net) wells, two of which were drilled during 2013. Delphi also focused on its infrastructure in the Bigstone area, investing $22.8 million, or 23 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 its 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 constructed the Company's nine mmcf/d compression/dehydration facility and gathering system to handle Delphi's Montney production in the southern part of East Bigstone. The Company has also completed pipeline connections to deliver its Montney natural gas and natural gas liquids from its two Bigstone facilities to the SemCams K3 processing facility. The Company spent $8.8 million on the acquisition of undeveloped properties and $8.9 million on the acquisition of developed properties, including a natural gas processing facility which were partially funded by proceeds on dispositions of $16.6 million.

During the third quarter of 2014, the Company closed the sale of certain interests from its Hythe property for net proceeds of $15.8 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. Also in 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 fourth quarter of 2014, Delphi acquired production, undeveloped land and a natural gas processing facility in West Bigstone for a cash purchase price of $8.9 million after closing adjustments. The acquisition consists of approximately 430 boe/d (87 percent natural gas) of production 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 December 31, 2014, Delphi has a working interest in a total of 101.5 gross (86.8 net) sections of undeveloped land as part of 138.5 gross (117.1 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 December 31			Twelve Months Ended December 31		
	2014	2013	% Change	**2014**	2013	% Change
Land [1]	**(686)**	115	(697)	**394**	342	15
Seismic	**13**	78	(83)	**127**	110	15
Drilling, completions and equipping	**16,217**	24,857	(35)	**74,331**	63,202	18
Facilities	**660**	1,933	(66)	**22,814**	6,047	277
Capitalized expenses	**643**	622	3	**3,034**	2,231	36
Other	**5**	19	(74)	**151**	24	529
Capital invested	**16,852**	27,624	(39)	**100,851**	71,956	40
Disposition of properties	**(651)**	-	-	**(16,615)**	(3,319)	401
Net capital invested	**16,201**	27,624	(41)	**84,236**	68,637	23
Acquisition of undeveloped properties	**-**	-	-	**8,800**	13,664	(36)
Acquisition of developed properties	**8,858**	-	-	**8,858**	-	-
Total capital invested	**25,059**	27,624	(9)	**101,894**	82,301	24

(1) In the third quarter of 2014, a $750 thousand deposit related to the acquisition of developed properties was included in this category.

PRODUCTION

What factors contributed to the production volumes?

Production volumes for the three months ended December 31, 2014 averaged 12,035 boe/d, a 34 percent increase over the comparative period. Production volumes have increased as a result of the Company's successful drilling program in the Montney formation at Bigstone. During the fourth quarter of 2014, two gross and net wells were brought on stream, of which one well was drilled during the third quarter of 2014. The production growth from the Montney was partially offset by natural declines and the disposition of the producing oil properties in Hythe at the end of the third quarter of 2014. In the fourth quarter of 2014, Montney production averaged 7,743 boe/d, up 99 percent from the production average of 3,884 boe/d in the fourth quarter of 2013.

Production volumes for 2014, averaged 10,549 boe/d compared to an average of 8,241 boe/d in 2013, representing an increase of 28 percent. 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 and the disposition of its producing oil properties in Hythe at the end of the third quarter of 2014. During 2014, nine gross (8.5 net) wells were brought on production. In 2014 production from the Montney increased by 124 percent to 6,344 boe/d, compared to 2013 average production of 2,837 boe/d.

The Company's production portfolio for the fourth quarter of 2014 was weighted 14 percent to field condensate, 17 percent to natural gas liquids and 69 percent to natural gas. This compares to a production portfolio for the comparative quarter in 2013 weighted eleven percent to field condensate, 14 percent to natural gas liquids, three percent to crude oil and 72 percent to natural gas. For the year ended December 31, 2014, Delphi's production portfolio was weighted 13 percent to field condensate, 16 percent to natural gas liquids, two percent to crude oil and 69 percent to natural gas. For the fourth quarter of 2014, the Montney production consisted of 20 percent field condensate, 15 percent natural gas liquids and 65 percent natural gas.

Field condensate as a percentage of total liquids increased to 44 percent for the three months ended December 31, 2014 compared to 38 percent for the comparative quarter in 2013. Despite the Company's disposition of producing oil properties in Hythe at the end of the third quarter of 2014, total liquids production for the fourth quarter of 2014 increased 47 percent and 35 percent compared to the fourth quarter of 2013 and the third quarter of 2014, respectively. Due to the liquids-rich natural gas play at Bigstone, the Company has increased its average corporate NGL and field condensate yield by 34 percent from 2013 to 71 bbls/mmcf.

	Three Months Ended December 31			Twelve Months Ended December 31		
	2014	2013	% Change	**2014**	2013	% Change
Field condensate (bbls/d)	**1,639**	960	71	**1,421**	691	106
Natural gas liquids (bbls/d)	**2,020**	1,286	57	**1,669**	1,222	37
Crude oil (bbls/d)	**53**	282	(81)	**171**	311	(45)
Total crude oil and natural gas liquids	**3,712**	2,528	47	**3,261**	2,224	47
Natural gas (mcf/d)	**49,939**	38,761	29	**43,729**	36,104	21
Total (boe/d)	**12,035**	8,988	34	**10,549**	8,241	28

REALIZED SALES PRICES

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

For the three months ended December 31, 2014, Delphi realized an average sales price of $33.75 per boe, a five percent decrease when compared to the same quarter in 2013. The reduction is primarily due to a decrease in realized natural gas and natural gas liquids prices.

For the year ended December 31, 2014, Delphi realized an average sales price of $40.23 per boe, a 20 percent increase in comparison to the same period in 2013. The increase in Delphi's realized average sales price is primarily due to an improvement in annual average commodity prices.

For the three months ended December 31, 2014, Delphi's realized natural gas price decreased three percent in comparison to the same period in 2013. The decrease is due to a reduction in the premium received for Delphi's heat content and marketing arrangements partially offset by an improvement in the average daily AECO benchmark price of two percent, a gain on physical commodity risk management contracts and a reduction in the loss on financial commodity risk management contracts. The reduction in the premium received for Delphi's heat content and marketing arrangements is primarily due to a change in the pricing structure of a certain marketing arrangement for natural gas sold in Alberta which is expected to continue until the end of November 2015.

For the year ended December 31, 2014, Delphi's realized natural gas price increased by 20 percent in comparison to the same period in 2013. The increase is due to an improvement in the average daily AECO benchmark price of 41 percent, an increase in the premium received for Delphi's heat content and marketing arrangements partially offset by a realized loss on financial commodity risk management contracts.

Realized crude oil and field condensate prices were two percent higher for the three months ended December 31, 2014 compared to the same period in 2013. The improvement is due to a gain on financial commodity risk management contracts and a narrowing differential partially offset by a decrease in Edmonton light.

Realized crude oil and field condensate prices were eight percent higher for the year ended December 31, 2014 compared to the same period in 2013. The improvement is due to a one percent increase in Edmonton light, a narrowing differential and a decrease in realized losses on financial commodity risk management contracts.

Delphi's realized natural gas liquids price for the fourth quarter of 2014 decreased 32 percent compared to the fourth quarter of 2013. The decrease is a result of weakening commodity prices for all natural gas liquids, specifically a 50 percent reduction in the realized sales price for propane, in combination with a significant increase in the sales volumes for propane.

Delphi's realized natural gas liquids price for the year ended December 31, 2014 increased four percent in comparison to the same period in 2013. The improvement in the realized average natural gas price is due to a 47 percent price increase for propane during the first three quarters of 2014 in combination with a change in the production mix due to higher plant condensate and pentane sales in comparison to the same period in 2013.

	Three Months Ended December 31			Twelve Months Ended December 31		
	2014	2013	% Change	**2014**	2013	% Change
AECO ($/mcf)	**3.60**	3.53	2	**4.48**	3.17	41
Heating content and marketing ($/mcf)	**0.04**	0.35	(89)	**0.39**	0.35	11
Realized price before risk management contracts ($/mcf)	**3.64**	3.88	(6)	**4.87**	3.52	38
Gain (loss) on physical contracts ($/mcf)	**0.07**	(0.06)	-	**-**	(0.01)	-
Gain (loss) on financial contracts ($/mcf)	**(0.01)**	(0.02)	(50)	**(0.52)**	0.10	(620)
Realized natural gas price ($/mcf)	**3.70**	3.80	(3)	**4.35**	3.61	20
Edmonton Light ($/bbl)	**75.63**	86.40	(12)	**94.38**	93.00	1
Quality differential ($/bbl)	**(1.02)**	(1.27)	(20)	**(0.05)**	(4.67)	(99)
Realized price before risk management contracts ($/bbl)	**74.61**	85.13	(12)	**94.33**	88.33	7
Gain (loss) on financial contracts ($/bbl)	**12.12**	(0.45)	-	**(1.13)**	(1.80)	(37)
Realized oil and field condensate price ($/bbl)	**86.73**	84.68	2	**93.20**	86.53	8
Delphi’s realized natural gas liquids price ($/bbl)	**35.20**	52.07	(32)	**50.07**	48.37	4
Total realized sales price ($/boe)	**33.75**	35.52	(5)	**40.23**	33.61	20

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 (loss). 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 (loss).

A summary of the Company's financial and physical commodity price risk management contracts are as follows:

Physical Contracts

Time Period	Type of Contract	Average Quantity Contracted	Average Price ($/unit)		Reference
January 2015 - March 2015	Natural Gas - fixed	11,806 GJ/d	$3.00	Cdn	AECO
April 2015	Natural Gas - fixed	10,000 GJ/d	$2.54	Cdn	AECO
January 2015 - March 2015	Natural Gas - fixed	3,000 mmbtu/d	$4.21	U.S.	Chicago
April 2015 - October 2015	Natural Gas - fixed	6,000 mmbtu/d	$2.84	U.S.	Chicago
November 2015	Natural Gas - fixed	6,000 mmbtu/d	$3.27	U.S.	Chicago

Financial Contracts

Time Period	Type of Contract	Quantity Contracted	Price ($/unit)		Reference
April 2013 – April 2015	Natural Gas - fixed	3,000 GJ/d	$3.54	Cdn	AECO
April 2013 – December 2015	Natural Gas - fixed	3,000 GJ/d	$3.27	Cdn	AECO
April 2013 – December 2016	Natural Gas - fixed	3,000 GJ/d	$3.40	Cdn	AECO
June 2013 – December 2016	Natural Gas - fixed	6,000 GJ/d	$3.45	Cdn	AECO
January 2015 – December 2015	Natural Gas - fixed	2,500 GJ/d	$3.67	Cdn	AECO
January 2015 – December 2015	Natural Gas - fixed	5,000 GJ/d	$3.69	Cdn	AECO
January 2015 – December 2015	Natural Gas - fixed	2,500 GJ/d	$3.80	Cdn	AECO
April 2015 – October 2015	Natural Gas - fixed	2,000 GJ/d	$2.71	Cdn	AECO
April 2015 – October 2015	Natural Gas - fixed	5,000 GJ/d	$3.23	Cdn	AECO
April 2015 – October 2015	Natural Gas - fixed	2,500 GJ/d	$3.49	Cdn	AECO
April 2015 – October 2015	Natural Gas - fixed	2,500 GJ/d	$3.62	Cdn	AECO
May 2015 – October 2015	Natural Gas - fixed	3,000 GJ/d	$3.20	Cdn	AECO
December 2015 – December 2016	Natural Gas - fixed	5,000 mmbtu/d	$3.45	U.S.	NYMEX
December 2015 – December 2018	Natural Gas - fixed	10,000 mmbtu/d	$3.56	U.S.	NYMEX
January 2016 – December 2016	Natural Gas - fixed	2,500 GJ/d	$3.69	Cdn	AECO
January 2017 – December 2017	Natural Gas - fixed	2,500 GJ/d	$3.75	Cdn	AECO
January 2016 – December 2017	Natural Gas - fixed	5,000 mmbtu/d	$3.86	U.S.	NYMEX
January 2015 – December 2015	Crude Oil – put option	1,220 bbls/d	$80.00	Cdn	WTI
January 2016 – December 2018	Crude Oil – fixed	200 bbls/d	$78.46	Cdn	WTI
January 2016 – December 2018	Crude Oil – fixed	200 bbls/d	$78.35	Cdn	WTI
January 2016 – December 2018	Crude Oil – collar (1)	400 bbls/d	$78.60 - $85.00	Cdn	WTI

(1) The collar has a deferred cost of $4.02 per barrel.

The fair value of the financial contracts outstanding as at December 31, 2014 is estimated to be an asset of approximately $20.1 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 year 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 months ended December 31, 2014, the derivative commodity contracts resulted in a realized gain of $1.8 million and an unrealized gain of $24.4 million. For the twelve months ended December 31, 2014, the derivative commodity contracts resulted in a realized loss of $9.0 million and an unrealized gain of $25.9 million. The unrealized gain for the three and twelve months ended December 31, 2014, is the difference between the fair value of the commodity risk management contracts outstanding as at December 31, 2014 and the fair value as at September 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 in 2014 compare to 2013 and what factors contributed to the change?

Delphi generated revenue of $35.5 million in the fourth quarter of 2014, a 21 percent increase over the comparative period. The increase in revenues is primarily due to higher natural gas, field condensate and natural gas liquids production partially offset by a reduction in crude oil revenue as the Company disposed of the majority of its producing oil properties during the third quarter of 2014.

For the year ended December 31, 2014, Delphi generated revenue of $163.9 million, a 63 percent increase in comparison to the same period in 2013. The increase in revenues is due to an improvement in realized sales prices in combination with higher natural gas, field condensate and natural gas liquids production, partially offset by a reduction in crude oil volumes as a result of the disposition of producing oil properties in the third quarter of 2014.

For the fourth quarter of 2014, field condensate and natural gas liquids contributed 50 percent of total revenues compared to 47 percent in the same period in 2013. For the year ended December 31, 2014, field condensate and natural gas liquids contributed 48 percent of total revenues compared to 43 percent in the same period in 2013.

	Three Months Ended December 31			Twelve Months Ended December 31		
	2014	2013	% Change	**2014**	2013	% Change
Natural gas	**16,714**	13,756	22	**77,712**	46,262	68
Natural gas physical contract gains (loss)	**359**	(203)	-	**18**	(84)	(121)
Field condensate	**11,220**	7,546	49	**48,822**	22,045	121
Natural gas liquids	**6,542**	6,160	6	**30,502**	21,574	41
Crude oil	**392**	2,181	(82)	**5,990**	10,258	(42)
Sulphur	**307**	20	1,435	**826**	375	120
Total	**35,534**	29,460	21	**163,870**	100,430	63

ROYALTIES

What were royalty costs in 2014?

For the fourth quarter of 2014, royalties totaled $4.4 million compared to $4.5 million in the same period in 2013. Crown royalties decreased from the fourth quarter of 2013 to the fourth quarter of 2014 primarily due to a significant reduction in crude oil royalties as the Company disposed of the majority of its producing oil properties in the third quarter of 2014 and a reduction in natural gas liquids royalties due to lower commodity prices. Gross overriding royalties in the fourth quarter of 2014 increased in comparison to the same period in 2013. The increase is primarily due to the addition of new wells in the Montney area which have been encumbered by a gross overriding royalty.

For the year ended December 31, 2014, royalties totaled $24.7 million compared to $13.2 million for the same period in 2013. Crown royalties increased seven percent in comparison to 2013 primarily due to an improvement in commodity prices in combination with higher production of natural gas, natural gas liquids and field condensate partially offset by a reduction in crude oil royalties due to the third quarter of 2014 disposition of producing oil properties. Gross overriding royalties increased significantly due to the addition of new wells in the Montney area which have been encumbered by a gross overriding royalty.

	Three Months Ended December 31			Twelve Months Ended December 31		
	2014	2013	% Change	**2014**	2013	% Change
Crown royalties	**2,722**	3,576	(24)	**14,226**	13,291	7
Royalty credits	**(1,374)**	(1,530)	(10)	**(5,182)**	(5,663)	(8)
Crown royalties – net	**1,348**	2,046	(34)	**9,044**	7,628	19
Gross overriding royalties	**3,083**	2,533	22	**15,620**	5,531	182
Total	**4,431**	4,579	(3)	**24,664**	13,159	87
Per boe	**4.00**	5.54	(28)	**6.41**	4.37	47

What were the average royalty rates paid on production in 2014?

For the three months ended December 31, 2014, the average royalty rate decreased to 12.6 percent, down from 15.4 percent in the comparative period in 2013. The decrease in the average rate is due to a decrease in the Crown royalty rate of 45 percent from the fourth quarter of 2013. The Crown royalty rate decreased primarily as a result of the disposition of the majority of the Company's producing oil properties in the third quarter of 2014 and increased production from wells that take advantage of the Alberta royalty incentive programs. The gross overriding royalty rate for the fourth quarter of 2014 increased by four percent compared to the same period in 2013. The increase is a result of higher production levels from wells which are encumbered with a gross overriding royalty.

For the year ended December 31, 2014, the average royalty rate increased 15 percent in comparison to the same period in 2013. The Crown royalty rate decreased as a result of increased production from wells that take advantage of the Alberta royalty incentive programs and a decrease in oil royalties due to the disposition of the majority of the Company's producing oil properties in the third quarter of 2014. These decreases were partially offset by an increase in the rates due to an improvement in natural gas and natural gas liquids prices. The gross overriding royalty rate increased to 9.6 percent for the year ended December 31, 2014. The increase is primarily due to the addition of new wells in the Montney area as well as higher production levels from certain Montney wells which are encumbered by a gross overriding royalty.

	Three Months Ended December 31			Twelve Months Ended December 31		
	2014	2013	% Change	**2014**	2013	% Change
Crown rate – net of royalty credits	**3.8%**	6.9%	(45)	5.5%	7.6%	(28)
Gross overriding rate	**8.8%**	8.5%	4	9.6%	5.5%	75
Average rate	**12.6%**	15.4%	(18)	15.1%	13.1%	15

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 2014 compare to 2013?

Production costs for the three and twelve months ended December 31, 2014 increased 36 percent and 35 percent, respectively as compared to the same periods in 2013. Production costs have increased generally due to higher production volumes in the three and twelve months ended December 31, 2014 compared to the same periods in 2013. Production volumes are up 34 percent for the three months ended December 31, 2014 and up 28 percent for the year. Production costs on a boe basis increased by five percent and eleven percent in the three and twelve months ended December 31, 2014, respectively, compared to the same periods in 2013. Included in the operating costs for the fourth quarter of 2014 is $0.75 million of costs related to the cleanup of a pipeline leak in the Bigstone area. Operating costs per boe are higher by $0.68 per boe in the fourth quarter and higher by $0.19 per boe for the year as a result of this expense.

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. Processing income decreased four percent and 14 percent in the three and twelve months ended December 31, 2014, respectively, compared to the same period in 2013.

	Three Months Ended December 31			Twelve Months Ended December 31		
	2014	2013	% Change	**2014**	2013	% Change
Production costs	**11,262**	8,276	36	**38,953**	28,782	35
Processing income	**(846)**	(882)	(4)	**(2,835)**	(3,300)	(14)
Total	**10,416**	7,394	41	**36,118**	25,482	42
Per boe	**9.41**	8.94	5	**9.38**	8.47	11

TRANSPORTATION EXPENSES

What factors contributed to the change in transportation costs in 2014?

For the three and twelve months ended December 31, 2014, transportation expenses increased 39 percent and 31 percent, respectively as compared to the same periods in 2013. The increase in transportation expenses is primarily due to the growth in Montney production which has field condensate emulsion trucking, field condensate trucking and gas gathering fees. The increase in transportation expenses is a reflection of higher production volumes in the three and the twelve months ended December 31, 2014 compared to the same periods in 2013. Field condensate emulsion and field condensate trucking charges increase specifically when new wells are brought on stream in the Bigstone area due to the high levels of field condensate produced. Treatment facilities in the Bigstone area have been extremely busy due to the significant number of Montney and Duvernay wells being drilled and completed in the area. This has resulted in a shortage of off-take capacity at the treatment facilities causing trucks to drive further to deliver product at other terminals or incur additional charges for waiting times at the facilities. Delphi has mitigated trucking charges related to waiting times to some extent by doubling the field condensate tank storage capacity to 6,000 barrels. On a per boe basis, transportation expenses increased four and two percent in the three and twelve months ended December 31, 2014, compared to the same time periods in 2013, reflecting the increase in transportation expenses partially offset by higher production volumes.

	Three Months Ended December 31			Twelve Months Ended December 31		
	2014	2013	% Change	**2014**	2013	% Change
Total	**3,649**	2,622	39	**13,927**	10,640	31
Per boe	**3.30**	3.17	4	**3.62**	3.54	2

GENERAL AND ADMINISTRATIVE

How do general and administrative costs in 2014 compare to 2013?

General and administrative ("G&A") expenses (after recoveries and allocations) for the three and twelve months ended December 31, 2014 were $0.8 million and $5.4 million, respectively, compared to $1.5 million and $6.2 million for the same periods in 2013, respectively.

Gross expenses in the fourth quarter of 2014 are twelve percent lower than the comparative period primarily due to lower consulting and service costs partially offset by higher personnel costs. Overhead recoveries increased 60 percent over the comparative period due to marketing fee allocations. Salary allocations in the fourth quarter of 2014 increased six percent over the comparative period in 2013 as a result of higher personnel costs.

For the year ended December 31, 2014, G&A expenses decreased 14 percent in comparison to the same period in 2013. Gross expenses in 2014 increased nine percent compared to 2013 primarily as a result of higher personnel costs partially offset by lower consulting and office costs. Overhead recoveries increased 55 percent and salary allocations increased 35 percent in comparison to the same period in 2013. The increase in overhead recoveries and salary allocations is due to higher personnel costs and marketing fee allocations.

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

	Three Months Ended December 31			Twelve Months Ended December 31		
	2014	2013	% Change	**2014**	2013	% Change
Gross expenses	**2,573**	2,932	(12)	**11,601**	10,602	9
Overhead recoveries	**(947)**	(593)	60	**(2,415)**	(1,556)	55
Salary allocations	**(844)**	(794)	6	**(3,828)**	(2,840)	35
General and administrative expenses	**782**	1,545	(49)	**5,358**	6,206	(14)
Per boe	**0.71**	1.87	(62)	**1.39**	2.06	(33)

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 ("RSUs") granted to employees, directors and key consultants of the Company. The fair value of RSUs 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 27 percent and nine percent for the three and twelve months ended December 31, 2014, respectively as compared to the same periods in 2013. The increase is primarily due to the grant of 2.2 million options with a higher weighted average fair value per option in comparison to the fair value of the options granted in 2013.

Share-based compensation expense related to the Company's RSUs decreased in the three and twelve months ended December 31, 2014 in comparison to the same periods in 2013. The decrease in the expense for the fourth quarter of 2014 compared to the same quarter in 2013 is due to a lower closing share price as at December 30, 2014 compared to December 30, 2013 in combination with a decrease in outstanding units. The decrease in the expense for the twelve months ended December 31, 2014 compared to the same period in 2013 is due to a lower closing share price as at December 30, 2014 compared to December 30, 2013 in combination with a decrease in outstanding units as at December 31, 2014 partially offset by higher closing share prices used for calculating the expense related to vested and paid out RSUs during the year. Capitalized share-based compensation decreased in the three and twelve months ended December 31, 2014 in comparison to the same periods in 2013 as a result of a re-allocation of the capitalized expense related to the RSUs.

During the year ended December 31, 2014, the Company paid out $2.3 million of share-based compensation expense related to the Company's RSUs of which $0.3 million was capitalized to property, plant and equipment. During the year ended December 31, 2013, the Company paid out $0.6 million of share-based cash compensation expense related to the Company's outstanding RSUs of which $0.2 million was capitalized to property, plant and equipment.

	Three Months Ended December 31			Twelve Months Ended December 31		
	2014	2013	% Change	**2014**	2013	% Change
Share-based compensation – Options	**658**	520	27	**2,314**	2,124	9
Share-based compensation – RSUs	**(1,154)**	571	(302)	**1,887**	1,960	(4)
Capitalized costs	**(297)**	(346)	(14)	**(906)**	(1,300)	(30)
Net	**(793)**	745	(206)	**3,295**	2,784	18
Per boe	**(0.71)**	0.90	(179)	**0.86**	0.93	(8)

GAIN ON PROPERTY DISPOSITIONS

What does the gain on property dispositions relate to?

During the third quarter of 2014, Delphi received proceeds of $15.8 million for the sale of certain interests in its Hythe cash generating unit ("CGU") with a net book value of $8.5 million, including decommissioning liabilities of $2.8 million, resulting in a gain of $7.3 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. In the fourth quarter of 2014, Delphi received proceeds of $0.8 million for the sale of minor interests in its Hythe and Miscellaneous Alberta CGUs. The interests sold had a net book value of $1.2 million, resulting in a loss on disposition of $0.4 million.

During 2013, Delphi received proceeds of $3.3 million for oil and gas properties with a net book value of $227.0 thousand and decommissioning liabilities of $54 thousand, resulting in a gain of $3.1 million.

FINANCE COSTS

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

For the three and twelve months ended December 31, 2014, interest charges increased 14 percent and 25 percent, respectively, compared to the same periods in 2013, as a result of a higher average debt balance partially offset with lower interest rates charged on the Company's outstanding bankers' acceptances. The bankers' acceptances outstanding at December 31, 2014 have terms ranging from 90 to 180 days and a weighted average effective interest rate of 4.47 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 throughout 2014 compared to 2013. The decommissioning obligation increased primarily due to changes in estimates.

The finance charge associated with the Company's subordinated debt is based on the effective interest rate method in order to amortize the prepaid finance fees and 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 December 31			Twelve Months Ended December 31		
	2014	2013	% Change	**2014**	2013	% Change
Interest	**2,053**	1,805	14	**7,592**	6,070	25
Accretion	**293**	435	(33)	**1,166**	1,013	15
Finance charges	**52**	72	(28)	**396**	157	152
Total finance costs	**2,398**	2,312	4	**9,154**	7,240	26
Interest per boe	**1.85**	2.18	(15)	**1.97**	2.02	(2)
Accretion per boe	**0.26**	0.53	(51)	**0.30**	0.34	(12)
Finance charges per boe	**0.05**	0.09	(44)	**0.10**	0.05	100

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 which matured on February 28, 2015. The swap transaction has a fixed interest rate of 1.25 percent.

DECOMMISSIONING EXPENSE

What does the decommissioning expense relate to?

For the twelve months ended December 31, 2014, and December 31, 2013, the Company recognized $0.4 million and $0.5 million, respectively, of decommissioning expense. The decommissioning expense is the difference between decommissioning expenditures incurred in the period and the carrying amount of the Company's decommissioning obligation for those specific assets. The expense recorded primarily relates to difficulties experienced during the abandonment of a well in British Columbia.

DEPLETION, DEPRECIATION AND IMPAIRMENT

Has the Company's depletion and depreciation rate and expense changed in 2014 compared to 2013?

Depletion and depreciation before impairment loss for the three months ended December 31, 2014 increased 34 percent compared to the same period in 2013. The increase was primarily due to higher production volumes in combination with a slight increase in the depletion rate. The depletion rate for the fourth quarter of 2014 increased due to higher future development costs largely offset by an increase in the reserve base.

In the fourth quarter of 2014, due to minimal capital spending in all CGUs with the exception of Bigstone, and a decrease in the forward price curves for natural gas and crude oil, Delphi determined that impairment indicators were present in all CGUs, other than Bigstone. As a result of the impairment tests, Delphi recognized $56.5 million of impairments relating to its Hythe, Wapiti, Berland River and Miscellaneous Alberta CGUs. The impairments were based on the difference between the period end carrying value of the CGUs 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 15 to 20 per cent.

Depletion and depreciation before impairment loss for the twelve months ended December 31, 2014 increased 25 percent compared to the same period in 2013 primarily due to higher production volumes. The depletion and depreciation rate decreased in 2014 compared to 2013 primarily due to a higher reserve base partially offset by higher future development costs.

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 CGUs 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 12 to 20 per cent.

	Three Months Ended December 31			Twelve Months Ended December 31		
	2014	2013	% Change	**2014**	2013	% Change
Depletion and depreciation	**14,010**	10,432	34	**44,929**	36,018	25
Impairment loss	**56,548**	15,300	270	**56,548**	15,300	270
Total	**70,558**	25,732	174	**101,477**	51,318	98
Depletion and depreciation per boe	**12.65**	12.62	-	**11.67**	11.97	(3)
Impairment loss per boe	**51.07**	18.50	176	**14.69**	5.09	189

INCOME TAXES

What was the impact on deferred income taxes as a result of the loss for the period?

Delphi recorded a deferred income tax recovery of $8.4 million and $1.9 million for the three and twelve months ended December 31, 2014, respectively. Deferred taxes arise from differences between the accounting and tax bases of the Company's assets and liabilities.

	Three Months Ended December 31			Twelve Months Ended December 31		
	2014	2013	% Change	**2014**	2013	% Change
Deferred income taxes recovery	**(8,355)**	(4,679)	79	**(1,875)**	(3,659)	(49)
Per boe	**(7.55)**	(5.66)	33	**(0.49)**	(1.22)	(60)

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 2014 compare to 2013?

Delphi's cash flow from operating activities of $23.0 million for the three months ended December 31, 2014 increased $17.1 million compared to the same period in 2013. The increase in cash flows from operating activities from the fourth quarter of 2013 to the fourth quarter of 2014 is primarily due to the change in non-cash working capital. The increase in funds from operations is primarily due to higher petroleum and natural gas sales, realized gains on financial commodity risk management contracts and a reduction in general and administrative costs partially offset by higher operating, transportation and interest costs.

For 2014, Delphi generated cash flow from operating activities of $74.0 million, a 136 percent increase from 2013. The increase in cash flows from operating activities from 2013 to 2014 is primarily due to the change in non-cash working capital and a reduction in decommissioning expenditures. The Company generated funds from operations of $65.2 million for the twelve months ended December 31, 2014, up 67 percent from the comparative period in 2013. The increase in funds from operations in 2014 is primarily due to higher petroleum and natural gas sales and a reduction in general and administrative costs partially offset by higher royalties, operating, transportation and interest costs and realized losses on financial commodity risk management contracts.

	Three Months Ended December 31			Twelve Months Ended December 31		
	2014	2013	% Change	**2014**	2013	% Change
Cash flow from operating activities	**23,001**	5,887	291	**74,036**	31,383	136
Accretion of subordinated and long term debt	**381**	(226)	-	**332**	298	11
Decommissioning expenditures	**86**	165	(48)	**1,160**	1,651	(30)
Change in non-cash working capital	**(7,599)**	5,526	(238)	**(10,369)**	5,783	(279)
Funds from operations	**15,869**	11,352	40	**65,159**	39,115	67

NET LOSS

What factors contributed to the loss in 2014?

For the three months ended December 31, 2014, Delphi recorded a net loss of $25.6 million ($0.16 loss per basic and diluted share), compared to a net loss of $16.1 million ($0.11 loss per basic and diluted share) in the same period in 2013. The increase in the net loss is due to an increase in operating, transportation, exploration and evaluation and depletion and impairment charges partially offset by an increase in petroleum and natural gas sales, realized and unrealized gains on financial commodity risk management contracts, a decrease in general and administrative costs and share-based compensation and a greater deferred income tax recovery.

For the twelve months ended December 31, 2014, Delphi recorded a net loss of $7.3 million ($0.05 loss per basic and diluted share) compared to a net loss of $11.6 million ($0.08 loss per basic and diluted share) in the same period in 2013. The decrease in the net loss is due to an increase in petroleum and natural gas sales, unrealized gains on financial commodity risk management contracts, an increase in the gain on dispositions partially offset by realized losses on financial commodity risk management contracts, an increase in royalties, operating, transportation, exploration and evaluation, depletion and impairment and finance costs as well as a reduction in the deferred income tax recovery.

	Three Months Ended December 31			Twelve Months Ended December 31		
	2014	2013	% Change	**2014**	2013	% Change
Net loss	**(25,588)**	(16,100)	59	**(7,263)**	(11,627)	(38)
Per boe	**(23.10)**	(19.46)	19	**(1.89)**	(3.86)	(51)
Per basic and diluted share	**(0.16)**	(0.11)	45	**(0.05)**	(0.08)	(38)

CASH NETBACK AND EARNINGS ANALYSIS

How do Delphi's netbacks achieved in 2014 compare to 2013?

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 December 31, 2014, Delphi's cash netback per boe increased four percent compared to the same period in 2013. The increase in the cash netback per boe from the fourth quarter of 2013 to that of 2014 is due to a decrease in royalties, general and administration and interest costs partially offset by a lower average realized sales price, an increase in operating and transportation charges and an increase in the value of paid out RSUs.

For the twelve months ended December 31, 2014, Delphi's cash netback per boe increased 30 percent compared to the same period in 2013. The increase in the cash netback per boe from 2013 to 2014 is due to improved average realized sales prices, a reduction in general and administrative and interest expenses partially offset by higher royalties, operating and transportation costs as well as an increase in the value of paid out RSUs.

	Three Months Ended December 31			Twelve Months Ended December 31		
	2014	2013	% Change	**2014**	2013	% Change
Barrels of oil equivalent ($/boe)						
Realized sales price	**33.75**	35.52	(5)	**40.23**	33.61	20
Royalties	**4.00**	5.54	(28)	**6.41**	4.37	47
Operating expenses	**9.41**	8.94	5	**9.38**	8.47	11
Transportation	**3.30**	3.17	4	**3.62**	3.54	2
Operating netback	**17.04**	17.87	(5)	**20.82**	17.23	21
General and administrative expenses	**0.71**	1.87	(62)	**1.39**	2.06	(33)
Paid out restricted share units	**0.15**	0.09	67	**0.53**	0.14	279
Interest	**1.85**	2.18	(15)	**1.97**	2.02	(2)
Cash netback	**14.33**	13.73	4	**16.93**	13.01	30
Unrealized loss (gain) on commodity risk contracts	**(22.02)**	5.89	(474)	**(6.74)**	0.62	(1,187)
Share-based compensation expense	**(0.86)**	0.81	(206)	**0.33**	0.78	(58)
Loss (gain) on dispositions	**0.52**	-	-	**(2.10)**	(1.04)	102
Exploration and evaluation	**3.28**	0.38	763	**0.94**	0.10	840
Loss on decommissioning	**0.04**	0.04	-	**0.11**	0.18	(39)
Depletion, depreciation and impairment	**63.72**	31.12	105	**26.36**	17.06	55
Accretion and finance charges	**0.31**	0.61	(49)	**0.40**	0.39	3
Deferred income taxes	**(7.55)**	(5.66)	33	**(0.49)**	(1.22)	(60)
Net loss	**(23.11)**	(19.46)	19	**(1.88)**	(3.86)	(51)

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 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. 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. During the fourth quarter of 2014, Delphi achieved record production of 12,035 boe/d, an increase of 34 percent compared to the same quarter in 2013. The increase in production is reflective of the capital invested in the development of the Montney play at East Bigstone. In 2014, Delphi drilled a total of eight gross (7.6 net) wells and has brought on production nine gross (8.5 net) wells, of which two wells were drilled during 2013. During the third quarter of 2014, the Company disposed of certain interests from its Hythe property for net proceeds of $15.8 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) of production, 26.3 gross (19.3 net) sections of undeveloped land and a natural gas processing plant in West Bigstone for $8.9 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. The semi-annual review of the Company's senior extendible revolving term credit facility was conducted during the fourth quarter of 2014 resulting in an additional $20.0 million increase in the borrowing base to $190.0 million. During the fourth quarter of 2014, the Company extended the maturity date of its $20.0 million subordinated debt from December 31, 2014 to June 30, 2016.

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 2013 and 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 2014 have improved since 2013, record levels of production are once again causing a supply/demand imbalance, particularly in the fourth quarter of 2014 and so far into 2015. The average spot price for AECO in 2013 was $3.17 per mcf and $4.48 per mcf in 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 $9.43 per proved plus probable boe in 2013 versus $10.35 per proved plus probable boe in 2014.

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

	Dec. 31, 2014	Sep. 30, 2014	Jun. 30, 2014	Mar. 31, 2014	Dec. 31, 2013	Sep. 30, 2013	Jun. 30, 2013	Mar. 31, 2013
Production								
Oil and field condensate (bbls/d)	**1,692**	1,396	1,583	1,697	1,242	1,035	988	735
Natural gas liquids (bbls/d)	**2,020**	1,356	1,807	1,493	1,286	1,294	1,115	1,189
Natural gas (mcf/d)	**49,939**	40,251	42,040	42,673	38,761	38,807	33,189	33,574
Barrels of oil equivalent (boe/d)	**12,035**	9,461	10,397	10,302	8,988	8,797	7,635	7,520
Financial								
Petroleum and natural gas revenue	**35,534**	35,117	44,173	49,046	29,459	25,666	23,541	21,763
Funds from operations	**15,869**	14,221	14,660	20,409	11,352	9,972	8,408	9,383
Per share – basic	**0.10**	0.09	0.09	0.13	0.07	0.07	0.05	0.06
Per share – diluted	**0.10**	0.09	0.09	0.12	0.07	0.06	0.05	0.06
Net earnings (loss)	**(25,588)**	12,163	5,439	723	(16,100)	1,208	3,209	56
Per share – basic	**(0.16)**	0.08	0.04	-	(0.11)	0.01	0.02	-
Per share – diluted	**(0.16)**	0.08	0.03	-	(0.11)	0.01	0.02	-

On an annual basis, how has Delphi performed?

The annual results for 2013 and 2014 have been impacted by the volatility of commodity prices, property dispositions and the successful drilling program in Bigstone.

In 2013, Delphi continued to focus its capital program on its liquids-rich resource in East Bigstone. The Company utilized a new slickwater hybrid completion technique on the wells completed in 2013, which has significantly decreased initial production decline rates and improved productivity. Although the Company's 2013 capital program before acquisitions and dispositions was reduced by 14 percent in comparison to 2012, production for the year remained comparable to 2012 and production for the fourth quarter of 2013 increased 24 percent from the fourth quarter of 2012. Delphi also focused on increasing its land base in Bigstone by completing a strategic land acquisition in the centre of its Bigstone Montney acreage of 30 gross (26.8 net) sections of Montney rights directly offsetting Delphi's existing acreage and producing wells. In 2013, Delphi's cash flow from operating activities and funds from operations improved in comparison to 2012 primarily as a result of improved commodity prices and a change in product mix.

In 2014, Delphi focused on the continuing development of its Montney play but also on the infrastructure needed to support current and future development of the Montney. Delphi drilled eight gross (7.6 net) wells during 2014 and achieved record production in the fourth quarter of 2014 of 12,035 boe/d. In 2014, Delphi invested $22.8 million of its capital program 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 a nine mmcf/d compression/dehydration facility and gathering system to handle Delphi production in the southern part of East Bigstone. The Company has also completed pipeline connections to deliver its Montney natural gas and natural gas liquids from its East Bigstone facilities to the SemCams K3 processing facility.

In 2014, the Company disposed of certain interests from its Hythe property for net proceeds of $15.8 million, after closing adjustments. The proceeds of the disposition were used to partially fund an acquisition of eight gross (3.5 net) sections 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) of production, 26.3 gross (19.3 net) sections of undeveloped land and a natural gas processing plant in West Bigstone for $8.9 million, after closing adjustments.

As a result of a successful year of development, the Company's senior lenders completed their annual and semi-annual review of the syndicated credit facility in the first and fourth quarters of 2014, respectively, which resulted in increases to the borrowing base of the facility. The syndicated credit facility has been increased by a total of $50.0 million in 2014, resulting in a $190.0 million borrowing base. During the fourth quarter of 2014, the Company extended the maturity date of its $20.0 million subordinated debt from December 31, 2014 to June 30, 2016.

The following table sets forth selected consolidated financial information of the Company for the most recently completed year ended December 31, 2014 and for the years ended 2013 and 2012:

	2014	2013	2012
Revenue	**163,870**	100,430	85,754
Net loss	**(7,263)**	(11,627)	(58,030)
Per share – basic	**(0.05)**	(0.08)	(0.43)
Per share – diluted	**(0.05)**	(0.08)	(0.43)
Total assets	**481,749**	451,680	401,649
Net debt	**173,655**	138,340	92,815

CONTRACTUAL OBLIGATIONS

Does the Company have any contractual obligations as of December 31, 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 are as follows:

	2015	2016	2017	2018	2019	Thereafter
Gathering, processing and transmission [(1)]	8,411	21,505	26,961	27,654	27,463	22,881
Office, equipment and software leases	2,102	1,414	991	-	-	-
Accounts payable and accrued liabilities [(2)]	40,215	-	-	-	-	-
Decommissioning obligations [(3)]	477	178	636	9,899	807	38,053
Restricted share units	882	262	44	-	-	-
Interest payments on subordinated debt	2,100	1,044	-	-	-	-
Long term debt	-	138,000	-	-	-	-
Subordinated debt	-	20,300	-	-	-	-
Total	54,187	182,703	28,632	37,553	28,270	60,934

(1) Balances denominated in US dollars have been translated at the December 31, 2014 exchange rate.
(2) Excludes the current portion of the restricted share units as they are disclosed separately on this table.
(3) Amounts represent the inflated, discounted future abandonment and reclamation expenditures anticipated to be incurred over the life of the Company's properties.

During the fourth quarter of 2014, Delphi entered into an agreement with Alliance Pipeline Ltd. for full path service to deliver up to 62.8 million cubic feet per day ("mmcf/d") of natural gas volumes by the end of 2017 into the Chicago gas market as follows:

	Dec. 2015 to Q1 2016	Q2 2016	Q3 2016	Q4 2016	Q1 2017	Q2 2017	Q3 2017	Q4 2017	Years 2018 - 2020
Volumes (mmcf/d)	35.3	40.3	45.3	50.3	50.3	55.3	60.3	62.8	62.8

Delphi's fourth quarter of 2014 average natural gas production was 49.9 mmcf/d.

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

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

The judgments, estimates and assumptions that have the most significant effect on the amounts recognized in the consolidated financial statements are included in the following:

i) Oil and gas reserves – reserves and resources are used in the units of production calculation for depreciation, depletion and amortization and the impairment analysis which affect the net earnings (loss). There are numerous uncertainties inherent in estimating oil and gas reserves. Estimating reserves is very complex, requiring many judgments based on geological, geophysical, engineering and economic data. Changes in these judgments could have a material impact on the estimated reserves. These estimates may change, having either a negative or positive effect on net profit as further information becomes available and as the economic environment changes.

ii) Depletion and depreciation – management estimates the useful lives of production equipment and other assets based on the period during which the assets are expected to be available for use. For crude oil and natural gas properties, the estimated useful lives are based on proved and probable reserves as determined annually by the Company's independent engineers and internal estimates on a quarterly basis determined in accordance with National Instrument 51-101 ("NI 51-101") and the Canadian Oil and Gas Evaluation Handbook ("COGEH").

Calculations for the depletion of crude oil and natural gas properties are based on total capitalized costs plus estimated future development costs of proved and probable reserves less the estimated net realizable value of production equipment and facilities after the proved reserves are fully produced.

iii) Recoverability of asset carrying values – Delphi's assets are aggregated into CGUs for the purpose of calculating impairment based on their ability to generate largely independent cash inflows. CGUs have been determined based on similar geological structure, geographical proximity, production profiles and infrastructure of its assets. By nature, these assumptions are subject to management's judgment and may impact the carrying value of the Company's assets in future periods. The Company's CGUs could change in the future as a result of development, acquisition or disposition activity.

The assessment of any impairment of property, plant and equipment is dependent upon estimates of recoverable amount that take into account factors such as reserves, economic and market conditions, discount rates, timing of cash flows, the useful lives of assets and their related salvage values. In determining whether oil and gas properties are impaired, each CGU's carrying value is compared to its recoverable amount, defined as the greater of its fair value less costs to sell and value in use.

The recoverable amount of Delphi's CGUs were estimated as their fair value less costs to sell based on the following information:

- the net present value, using pre-tax discount rates, of expected future cash flows based on proved and probable reserves as estimated by the Company's independent engineers; and
- the fair value of undeveloped land based on estimates provided by Delphi's independent land evaluator.

Key input estimates used in the determination of cash flows from oil and gas reserves include the following:

- Reserves - Assumptions that are valid at the time of reserve estimation may change significantly when new information becomes available. Changes in forward commodity price estimates, production costs or recovery rates may change the economic status of reserves and may ultimately result in reserves being adjusted.
- Oil and gas prices - Forward price estimates of oil and natural gas prices are used in the cash flow model. Commodity prices have fluctuated widely in recent years due to global and regional factors including supply and demand fundamentals, inventory levels, exchange rates, weather, economic and geopolitical factors.
- Discount rate - The discount rate used to calculate the net present value of cash flows is based on an estimate of acquisition metrics of recent transactions completed on similar assets to those contained within the relevant CGU. Changes in the general economic environment could result in significant changes to this estimate.

iv) Decommissioning obligations – provisions for decommissioning obligations associated with the Company's drilling operations are based on current legal and constructive requirements, technology, price levels and expected plans for remediation. Actual costs and timing of cash outflows can differ from estimates because of changes in laws and regulations, public expectations, prices, discovery and analysis of site conditions, changes in clean up technology and changes in discount rates.

v) Share-based compensation - the fair value of stock options granted is measured using a Black-Scholes option pricing model. Measurement inputs such as the expected volatility, expected life of the options and a forfeiture rate require management judgment and estimates. The Company estimates volatility based on weighted average historical traded daily volatility. The expected life of the options is estimated by using an average life for awards based on historical plan records. Management also makes an estimate of the number of options that will be forfeited based on historical information. The estimated forfeiture rate is adjusted to reflect actual forfeitures. Dividends are not taken into consideration as the Company does not expect to pay dividends.

vi) Business combinations – business combinations are accounted for using the acquisition method of accounting. The determination of fair value requires management to make assumptions and estimates about future events. The assumptions and estimates with respect to determining 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 and liabilities in the purchase price allocation.

vii) Deferred income taxes – deferred income tax assets and liabilities are recognized for the estimated tax consequences between amounts included in the financial statements and their tax base using substantively enacted future income tax rates. Timing of future revenue streams and future capital spending changes can affect the timing of the reversal of temporary differences and accordingly affect the amount of the deferred income tax asset or liability calculated at a point in time. These differences could materially impact earnings (loss).

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?

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.

The following are future accounting standards and amendments to current standards:

In May of 2014, the International Accounting Standards Board ("IASB"), issued "Accounting for Acquisitions of Interests in Joint Operations", amendments to IFRS 11, "Joint Arrangements." The amendments require business combination accounting to be applied to the acquisitions of interests in a joint operation that constitute a business. The amendments apply prospectively for annual periods beginning on or after January 1, 2016. Earlier application is permitted. The Company does not anticipate early adoption of this standard and the extent of the impact of adoption of the standard has not yet been determined.

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 Company's President and Chief Executive Officer and Senior Vice President, Finance and Chief Financial Officer have concluded that the Company's internal controls over financial reporting and disclosure controls and procedures are effective and provide a reasonable level of assurance that information required to be disclosed by the Company is recorded, processed, summarized and reported within the time periods specified. Management's assessment of the Company's internal controls over financial reporting was based on the framework in Internal Control over Financial Reporting – Guidance for Smaller Public Companies issued by the Committee of Sponsoring Organizations of the Treadway Commission (1992 Framework).

The Company notes that while it believes the disclosure controls and procedures and internal controls over financial reporting provide a reasonable level of assurance that they are effective, it does not expect that the disclosure controls and procedures and internal controls will prevent all errors and fraud. A control system is designed to provide reasonable, not absolute, assurance that the objectives of the control system are met. There were no changes made to the disclosure controls and procedures or internal controls over financial reporting during the fourth quarter of 2014.

2015 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 2015?

The Company's average annual production in 2015 will be dependent upon the number of wells drilled, funded by cash flow, resulting in production between 11,000 and 12,000 boe/d. The production is expected to be split 30 percent to liquids and 70 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 2015?

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 six 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.

So far in 2015, natural gas storage levels have increased to levels higher than last year and slightly lower than the five year average. The increase in the storage levels compared to last year reflects both lower than expected heating demand this past winter and higher natural gas production. As a result of the high natural gas inventory storage levels and strong natural gas production rates, the average price for AECO in the first two months of 2015 has been $2.75 per thousand cubic feet ("mcf"). Consequently, Delphi is managing its forecast for AECO natural gas prices to average between $2.25 and $2.75 per mcf for the entire year.

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 imbalanced as global supply exceeds global demand. Global production has been increasing since the second quarter of 2014, primarily due to previously shut-in production from certain countries that are part of the Organization of the Petroleum Exporting Countries ("OPEC") coming back online and a significant increase in production by non-OPEC countries, particularly, the United Sates. Global demand is impacted by a slowing economy in China and increased energy efficiency in developed nations.

Due to this imbalance in supply and demand for crude oil, Delphi is currently managing its capital program based on an average WTI price for 2015 of U.S. $50.00 to U.S. $55.00 per barrel.

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.

In 2014 and into 2015, 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 average $0.80 Cdn. to U.S. dollar.

ROYALTIES

What average royalty rate does Delphi expect to pay in 2015?

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 2015. Royalties are not affected by gains or losses realized through the Company's risk management program.

For 2015, Delphi expects its royalty rate, after the deduction for royalty credits to average between twelve and 14 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 2015?

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 $3.00 to $3.25 per boe in 2015. 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 2015 are expected to average $8.25 to $8.50 per boe.

GENERAL & ADMINISTRATIVE AND FINANCE COSTS

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

In 2015, Delphi anticipates its general and administrative costs, net of capitalized amounts, to be approximately $1.70 to $1.90 per boe, very similar to 2014.

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 2015. Interest expense is expected to be approximately $2.25 to $2.50 per boe in 2015.

CAPITAL PROGRAM AND NET DEBT LEVELS

What are the Company's forecast capital expenditures and net debt levels for 2015?

The Company expects 2015 net capital expenditures to be between $45.0 and $60.0 million to drill, complete and tie-in four to six wells dependent on commodity prices and hence funds from operations. 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, 2015 to be between $170.0 and $175.0 million.

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.