MANAGEMENT'S DISCUSSION AND ANALYSIS

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

Delphi Energy Corp. ("Delphi" or the "Company") is an oil and gas company based in Calgary, Alberta, focused on the exploration, development, and production of crude oil, natural gas and natural gas liquids from properties located in Western Canada. Delphi's operations are concentrated in the Deep Basin of Northwest Alberta. The Company's common shares, senior secured notes, and warrants are listed on the Toronto Stock Exchange ("TSX") under the symbol "DEE", "DEE.NT", and "DEE.WT", respectively. Additional information about Delphi is available on the Canadian Securities Administrators' System for Electronic Distribution and Retrieval (SEDAR) at www.sedar.com and at the Company's website at www.delphienergy.ca.

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, 2017 and 2016 and should be read in conjunction with the audited consolidated financial statements and accompanying notes for the years ended December 31, 2017 and 2016. 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 6, 2018.

2017 ACCOMPLISHMENTS

- Drilled six (3.9 net) successful delineation wells and eleven (7.1 net) successful in-fill wells in the Company's Bigstone Montney property, as part of a 17 (11.0 net) well drilling program;
- Produced 8,401 barrels of oil equivalent per day ("boe/d"), a 14 percent increase from 7,392 boe/d in 2016. Average production in the fourth quarter of 2017 increased 35 percent to 9,588 boe/d compared to 7,127 boe/d in the fourth quarter of 2016;
- Field condensate production in the fourth quarter of 2017 increased to 2,374 barrels per day ("bbls/d"), a 77 percent increase from 1,338 bbls/d in the fourth quarter of 2016;
- Montney field condensate and natural gas liquids ("NGL") yields increased to 116 barrels per million cubic feet ("bbls/mmcf"), up from 106 bbls/mmcf in 2016, with field and plant condensate comprising 86 percent of the total;
- Field condensate and NGL accounted for 58 percent of crude oil and natural gas revenues in 2017 and 64 percent of crude oil and natural gas revenues in the fourth quarter;
- Realized a natural gas price of $4.05 per thousand cubic feet ("mcf") compared to an AECO price of $2.15 per mcf as a result of selling approximately 90 percent of our natural gas in Chicago via full-path transportation arrangements on Alliance and a hedging gain of $0.27 per mcf;
- Cash netbacks per boe increased by eight percent over the comparative year resulting in adjusted funds flow of $36.7 million, a 23 percent increase over 2016. Cash netbacks per boe in the fourth quarter of 2017 increased 29 percent resulting in adjusted funds flow of $14.1 million, a 74 percent increase over the comparative quarter of 2016;
- Acquired 13.5 net sections of Montney rights in the greater Bigstone area contiguous to the Company's current Montney lands;
- Invested $15.0 million in various infrastructure projects to handle additional sales volumes and provide for reduced operating expenses in 2018;
- Closed a $65.0 million financing by way of private placement consisting of $35.0 million of equity priced at $1.27 per common share and $30.0 million of senior secured notes; and
- Increased the borrowing base of the senior credit facilities by $15.0 million to $95.0 million upon completion of the lenders' semi-annual review during the fourth quarter and added a lender to the syndicate.

FINANCIAL AND OPERATIONAL HIGHLIGHTS

	Three months ended December 31			Twelve months ended December 31		
	2017	2016	% Change	**2017**	2016	% Change
Financial						
($ thousands, except per share)						
Crude oil and natural gas revenues	**30,896**	20,546	50	**101,836**	69,134	47
Net earnings (loss)	**(1,764)**	(25,461)	93	**6,902**	(41,114)	-
Per share – basic and diluted	**(0.01)**	(0.16)	94	**0.04**	(0.26)	-
Adjusted funds flow[1]	**14,144**	8,120	74	**36,670**	29,865	23
Per share – basic and diluted[1]	**0.08**	0.05	60	**0.21**	0.19	11
Net debt[1]	**136,421**	85,945	59	**136,421**	85,945	59
Capital expenditures, net of dispositions	**42,156**	(30,679)	-	**117,292**	(3,427)	-
Weighted average shares (000s)						
Basic	**185,472**	155,630	19	**173,171**	155,540	11
Diluted	**185,472**	155,630	19	**173,975**	155,540	12
Operating						
(boe conversion – 6:1 basis)						
Production:						
Field condensate (bbls/d)	**2,374**	1,338	77	**1,968**	1,444	36
Natural gas liquids (bbls/d)	**1,315**	1,125	17	**1,250**	1,183	6
Natural gas (mcf/d)	**35,391**	27,988	26	**31,098**	28,595	9
Total (Boe/d)	**9,588**	7,127	35	**8,401**	7,392	14
Average realized sales prices, before financial instruments						
Field condensate ($/bbl)	**64.20**	57.17	12	**59.14**	48.64	22
Natural gas liquids ($/bbl)	**47.34**	30.42	56	**35.42**	20.62	72
Natural gas ($/mcf)	**3.39**	4.00	(15)	**3.78**	3.28	15
Netbacks ($/boe)						
Crude oil and natural gas revenues	**35.03**	31.33	12	**33.22**	25.55	30
Marketing income [1]	**1.63**	-	-	**0.58**	-	-
Realized gain on financial instruments	**1.25**	2.93	(57)	**1.00**	6.51	(85)
Revenue, after realized financial instruments	**37.91**	34.26	11	**34.80**	32.06	9
Royalties	**(2.26)**	(1.89)	20	**(2.35)**	(2.49)	(6)
Operating expense	**(10.59)**	(9.57)	11	**(9.60)**	(7.70)	25
Transportation expense	**(4.62)**	(4.93)	(6)	**(5.67)**	(5.63)	1
Operating netback [1]	**20.44**	17.87	14	**17.18**	16.24	6
General and administrative expenses	**(1.39)**	(1.77)	(21)	**(2.14)**	(2.01)	6
Paid out restricted share units	**-**	-	-	**-**	(0.11)	100
Interest	**(3.02)**	(3.72)	(19)	**(3.08)**	(3.09)	-
Cash netback [1]	**16.03**	12.38	29	**11.96**	11.03	8

(1) Refer to non–GAAP measures

DRILLING OPERATIONS

	Three Months Ended December 31, 2017		Twelve Months Ended December 31, 2017	
	Gross	Net	Gross	Net
Wells drilled	4.0	2.6	17.0	11.0
Success rate (%)	100	100	100	100

In 2017, Delphi drilled 17 (11.0 net) wells in the Montney formation at Bigstone. In comparison, Delphi drilled six (4.2 net) wells in 2016 which were also focused on the Bigstone Montney formation.

CAPITAL EXPENDITURES

	Three Months Ended December 31			Twelve Months Ended December 31		
	2017	2016	% Change	**2017**	2016	% Change
Land	**49**	350	(86)	**2,196**	369	495
Drilling, completions and equipping	**39,640**	19,370	106	**98,610**	45,648	116
Facilities	**4,492**	1,618	177	**15,032**	5,527	172
Capitalized expenses	**528**	633	(17)	**2,670**	2,267	18
Other	**66**	6	1,000	**379**	1	37,800
Capital invested	**44,775**	21,977	(104)	**118,887**	53,812	121
Disposition of properties	**(2,619)**	(52,656)	95	**(2,445)**	(57,239)	96
Net capital invested	**42,156**	(30,679)	-	**116,442**	(3,427)	-
Acquisition of properties	**-**	-	-	**850**	-	-
Total capital	**42,156**	(30,679)	-	**117,292**	(3,427)	-

During the fourth quarter of 2017, Delphi invested $44.8 million, of which 89 percent was on drilling, completion and equipping operations. Delphi drilled four (2.6 net) wells and performed completion operations on five (3.2 net) wells in its Bigstone area. The Company directed 10 percent of its capital invested to infrastructure which includes the expansion of its water disposal facility and commencement of the construction of an amine gas sweetening facility.

In 2017, Delphi invested $118.9 million, of which 83 percent was directed toward the drilling of 17 (11.0 net) wells and completion of 16 (10.2 net) wells in its Bigstone area. In addition to drilling, completion and equipping operations, Delphi invested 13 percent in infrastructure. Delphi acquired a 17 million cubic feet per day ("mmcf/d") amine processing package and compressor to sweeten natural gas from the Montney, allowing it to be processed at its 25 percent owned facility at Bigstone West. A separator was installed to help with the current configuration of the 7-11 Montney facility and will become part of the amine plant. Commissioning of the amine plant is planned for the second quarter of 2018. A pipeline loop was installed from the 14-10 header to the 7-11 Montney facility to assist with gathering and amine system optimization. In addition, Delphi completed the expansion of its compression and dehydration facility in the southern part of East Bigstone ("5-8 Montney facility"). The facility was expanded to handle up to ten mmcf/d of raw natural gas and to store up to 800 barrels of water and 1,800 barrels of field condensate. The Company also acquired 13.5 net sections of Montney rights in the greater Bigstone area contiguous to the Company's current Montney lands.

During the year, Delphi received proceeds of $0.9 million for the sale of certain minor oil and gas interests in its Bigstone and Miscellaneous Alberta cash generating units and $1.5 million for the sale of equipment to be used in the amine facility to a working interest partner.

As of December 31, 2017, Delphi has a working interest in a total of 118.3 (81.9 net) sections of undeveloped land as part of 168.5 (111.1 net) sections of total land prospective for liquids-rich natural gas in the Montney formation, situated at its core area of Bigstone.

PRODUCTION

	Three Months Ended December 31			Twelve Months Ended December 31		
	2017	2016	% Change	**2017**	2016	% Change
Field condensate (bbls/d)	**2,374**	1,338	77	**1,968**	1,444	36
Ethane (bbls/d)	**6**	3	100	**8**	6	33
Propane (bbls/d)	**526**	474	11	**552**	501	10
Butane (bbls/d)	**429**	357	20	**398**	358	11
Pentanes & plant condensate (bbls/d)	**354**	291	22	**292**	318	(8)
Total field condensate and natural gas liquids	**3,689**	2,463	50	**3,218**	2,627	22
Natural gas (mcf/d)	**35,391**	27,988	26	**31,098**	28,595	9
Total (boe/d)	**9,588**	7,127	35	**8,401**	7,392	14

Production volumes in the fourth quarter of 2017 averaged 9,588 boe/d, a 35 percent increase over the comparative quarter in 2016. Field condensate and natural gas liquids increased 50 percent from the comparative quarter, exceeding the growth rate on a boe basis as a result of increased Montney field condensate and natural gas liquids yields from new wells. During the fourth quarter of 2017, Delphi brought on-stream six (3.9 net) wells. Fourth quarter 2016 production volumes include 414 boe/d which was disposed at the end of the fourth quarter of 2016.

Production volumes for the twelve months ended December 31, 2017 averaged 8,401 boe/d, a 14 percent increase over the comparative period in 2016. Incremental production volumes from the 15 (9.6 net) wells brought on-stream in 2017 was partially offset by natural declines, downtime due to planned turnarounds at third party and owned facilities in the second quarter and the disposition of various interests in certain wells in the Bigstone area to an industry partner in the fourth quarter of 2016 which had provided average production of 334 boe/d in 2016. Production volumes in the second quarter of 2017 were significantly impacted by the planned turnaround of the SemCAMS K3 natural gas processing facility which lasted for 36 days and the concurrent planned turnaround of Delphi's 7-11 Montney facility which lasted for nine days.

Delphi's production portfolio for the fourth quarter of 2017 was weighted 25 percent to field condensate, 13 percent to natural gas liquids and 62 percent to natural gas. This compares to a production portfolio for the comparative quarter in 2016 weighted 19 percent to field condensate, 16 percent to natural gas liquids and 65 percent to natural gas.

BUSINESS ENVIRONMENT

Benchmark Prices and Economic Parameters

	Three Months Ended December 31			Twelve Months Ended December 31		
	2017	2016	% Change	**2017**	2016	% Change
Natural Gas						
NYMEX (US $/mmbtu)	**2.94**	2.98	(1)	**3.11**	2.45	27
Chicago City Gate (US $/mmbtu)	**2.92**	3.01	(3)	**3.04**	2.49	22
AECO (CDN $/mcf)	**1.69**	3.09	(45)	**2.15**	2.16	-
Crude Oil						
West Texas Intermediate (US $/bbl)	**55.41**	49.34	12	**50.93**	43.39	17
Edmonton Light (CDN $/bbl)	**68.99**	61.65	12	**62.89**	53.05	19
Condensate to Edmonton Light Differential (CDN $/bbl)	**3.28**	(1.27)	-	**0.77**	(1.08)	-
Foreign Exchange						
Canadian to U.S. dollar	**0.79**	0.75	5	**0.77**	0.76	1
U.S. to Canadian dollar	**1.27**	1.33	(5)	**1.30**	1.32	(2)

Natural Gas

Delphi ships approximately 90 percent of its natural gas production through the Alliance pipeline system into the Chicago market.

The Chicago City Gate benchmark natural gas price decreased three percent and increased 22 percent for the three and twelve months ended December 31, 2017, in comparison to the same periods in 2016. Natural gas storage levels in the United States in 2017 were lower than the prior year, principally as a result of growth in LNG exports and pipeline exports to Mexico which were partially offset by higher production, resulting in higher U.S. natural gas prices in comparison to 2016.

AECO benchmark natural gas prices in 2017 were constrained principally as a result of restricted export capacity from Alberta along with growing supplies resulting in high gas storage levels and ongoing price weakness.

Natural Gas Liquids

Natural gas liquids, including 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. Propane pricing improved significantly from 2016 due to significant draws through the 2016/17 winter and spring of 2017. Inventory levels are down significantly from the same period last year. Natural gas liquids pricing has generally been supported by improvements in West Texas Intermediate ("WTI") in comparison to 2016.

Crude Oil

Global supply and demand fundamentals for crude oil improved since the first half of 2016. WTI averaged twelve percent and 17 percent higher in the three and twelve months ended December 31, 2017, in comparison to the same periods in 2016, respectively. Rising crude oil prices were driven by growing demand as well as OPEC's compliance to reduce production targets in 2017 and the decision to further extend production cuts to the end of 2018.

Canadian light oil prices experienced a small tightening of basis differential. Edmonton Light averaged $68.99 per barrel in the fourth quarter of 2017 and $62.89 per barrel for the year, up 12 percent and 19 percent compared to the same periods in 2016, respectively.

Canadian/United States Exchange Rate

The value of the Canadian dollar against its U.S. counterpart averaged U.S. $0.79 for the three months ended December 31, 2017, a five percent increase in comparison to the same period in 2016. The value of the Canadian dollar against its U.S. counterpart averaged U.S $0.77 for the twelve months ended December 31, 2017, a one percent increase from the comparative period in 2016. As a producer of natural gas sold in the United States, an increase in the Canadian dollar has a negative effect on the price received for production.

REALIZED SALES PRICES

	Three Months Ended December 31			Twelve Months Ended December 31		
	2017	2016	% Change	**2017**	2016	% Change
AECO ($/mcf)	**1.69**	3.09	(45)	**2.15**	2.16	-
Chicago to AECO differential (Cdn$/mcf)	**2.02**	0.91	122	**1.79**	1.14	57
Heating content and marketing ($/mcf)	**(0.32)**	-	-	**(0.17)**	(0.02)	750
Realized price before risk management contracts ($/mcf)	**3.39**	4.00	(15)	**3.78**	3.28	15
Gain (loss) on financial contracts ($/mcf)	**0.47**	0.49	(4)	**0.27**	1.18	(77)
Gain (loss) on physical contracts ($/mcf)	**-**	-	-	**-**	(0.01)	-
Realized natural gas price ($/mcf)	**3.86**	4.49	(14)	**4.04**	4.46	(9)
Edmonton Light ($/bbl)	**68.99**	61.65	12	**62.89**	53.05	19
Condensate to Edmonton Light Differential (CDN $/bbl)	**3.28**	(1.27)	-	**0.77**	(1.08)	-
Differential ($/bbl)	**(8.07)**	(3.21)	151	**(4.52)**	(3.33)	36
Realized price before risk management contracts ($/bbl)	**64.20**	57.17	12	**59.14**	48.64	22
Gain (loss) on financial contracts ($/bbl)	**(1.89)**	5.41	(135)	**(0.01)**	9.97	(100)
Realized field condensate price ($/bbl)	**62.31**	62.58	-	**59.13**	58.61	1
Realized natural gas liquids price ($/bbl)	**47.34**	30.42	56	**35.42**	20.62	72
Total realized sales price ($/boe)	**36.28**	34.27	6	**34.22**	32.06	7

For the three and twelve months ended December 31, 2017, Delphi's combined realized sales price per boe increased six percent and seven percent in comparison to the same periods in 2016.

Delphi ships the majority of its natural gas production through the Alliance pipeline system into the Chicago market. This allows Delphi to sell its natural gas into a market where a more balanced supply and demand exist as opposed to selling its natural gas in Western Canada. Accordingly, Chicago City Gate is the primary benchmark for Delphi's natural gas sales in the United States.

For the three months ended December 31, 2017, Delphi's realized natural gas price before risk management contracts decreased 15 percent in comparison to the same period in 2016 primarily due to a decrease in AECO and Chicago City Gate benchmarks and an increase in the value of the Canadian dollar against its U.S. counterpart. Delphi's realized natural gas price before risk management contracts increased 15 percent for the year ended December 31, 2017 compared to the same period in 2016 due to increased Chicago City Gate prices partially offset by a higher Canadian dollar and an increase in the Chicago to AECO differential resulting in a larger heating content and marketing discount related to AECO natural gas sales.

Realized field condensate prices before risk management contracts were twelve percent and 22 percent higher in the three and twelve months ended December 31, 2017, respectively, compared to the same periods in 2016. Edmonton light increased twelve percent and 19 percent in the three and twelve months ended December 31, 2017 compared to the fourth quarter of 2016 and the twelve months ended December 31, 2016 as a result of an improvement in the global crude oil supply and demand imbalance. Condensate traded at a premium to Edmonton Light in the three and twelve months ended December 31, 2017 due to higher demand for condensate as a diluent for transporting heavy oil. The differential for the Company's field condensate increased in the three and twelve months ended December 31, 2017 due to an increase in density.

Delphi's realized natural gas liquids price for the three and twelve months ended December 31, 2017 increased 56 percent and 72 percent compared to the same periods in 2016 as a result of increased demand for propane, butane and plant condensate.

RISK MANAGEMENT ACTIVITIES

Delphi enters into both financial and physical commodity contracts as part of its risk management program to manage commodity price fluctuations designed to protect cash flows through to simple payout on the drilling and completion portion of its capital program.

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 Contracts

Time Period	Type of Contract	Quantity Contracted	Average Price ($/unit)		Reference
January 2017 – December 2018	Financial - Swap	3,000 mmbtu/d	$2.77	U.S.	NYMEX
April 2017 – October 2018	Financial - Swap	2,500 mmbtu/d	$4.16	Cdn	NYMEX
January 2018 – December 2018	Financial - Swap	3,000 mmbtu/d	$4.01	Cdn	NYMEX
January 2018 – December 2018	Financial - Swap	2,500 mmbtu/d	$4.17	Cdn	NYMEX
January 2018 – December 2019	Financial - Swap	2,000 mmbtu/d	$4.02	Cdn	NYMEX
January 2018 – December 2019	Financial - Swap	5,000 mmbtu/d	$3.84	Cdn	NYMEX

Crude Oil Contracts

Time Period	Type of Contract	Quantity Contracted	Price ($/unit)		Reference
January 2017 – December 2019	Financial - Swap	300 bbls/d	$70.00	Cdn	WTI
October 2017 – June 2018	Financial - Swap	200 bbls/d	$65.05	Cdn	WTI
January 2018 – March 2018	Financial - Swap	100 bbls/d	$64.85	Cdn	WTI
January 2018 – June 2018	Financial - Swap	200 bbls/d	$64.65	Cdn	WTI
January 2018 – December 2018	Financial - Swap	250 bbls/d	$71.60	Cdn	WTI
January 2018 – December 2018	Financial - Swap	250 bbls/d	$72.00	Cdn	WTI
January 2018 – December 2018	Financial - Swap	300 bbls/d	$70.70	Cdn	WTI

Basis Differential Contracts

Delphi ships the majority of its natural gas production through the Alliance pipeline system into the Chicago market. As a result, the Company has entered into Chicago – NYMEX basis differential contracts in order to fix the basis on a portion of its natural gas sales in the Chicago market.

Time Period	Type of Contract	Quantity Contracted	Differential (U.S. $/unit)
January 2018 – December 2018	Financial - Swap	4,000 mmbtu/d	$0.215
January 2018 – December 2018	Financial - Swap	4,000 mmbtu/d	$0.208
January 2018 – December 2018	Financial - Swap	4,000 mmbtu/d	$0.200
January 2018 – December 2018	Financial - Swap	4,000 mmbtu/d	$0.180
April 2018 – March 2019	Financial - Swap	4,000 mmbtu/d	$0.235

U.S Forward Exchange contracts

Delphi sells the majority of its natural gas in the Chicago market in U.S. dollars. In order to mitigate the U.S. to Canadian dollar fluctuation, Delphi has entered into the following U.S. dollar forward exchange contracts:

Time Period	Average Notional U.S. $	Average Exchange Rate (U.S.$ to Cdn$)
May 2015 – December 2018	250.0	1.2574
January 2018 – December 2018	800.0	1.2805
January 2018 – December 2018	400.0	1.2820

Interest rate swaps

Delphi has the following interest rate swap on borrowings through bankers' acceptances:

Time Period	Notional $	Fixed Interest Rate
February 2016 – January 2018	15,000	0.64%

Fair value of Delphi's risk management contracts

The fair value of the financial contracts outstanding as at December 31, 2017 is estimated to be a net asset of $0.9 million. The fair values of these contracts are based on an approximation of the amounts that would have been paid to or received from counterparties to settle the contracts outstanding at the end of the period having regard to forward prices and market values provided by independent sources. Due to the inherent volatility in commodity prices, foreign exchange and interest rates, actual amounts realized may differ from these estimates.

For the three and twelve months ended December 31, 2017, Delphi recorded an unrealized loss on its risk management contracts of $3.4 million and an unrealized gain of $9.9 million, respectively. The unrealized loss recognized for the three months ended December 31,2017 is the difference between the fair values of the risk management contracts outstanding as at December 31, 2017 and the fair values as at September 30, 2017. The unrealized gain recognized for the twelve months ended December 31, 2017 is the difference between the fair values of the risk management contracts outstanding as at December 31, 2017 and the fair values as at December 31, 2016.

For the three and twelve months ended December 31, 2017, the risk management contracts resulted in a realized gain of $1.1 million and $3.1 million, respectively. During the second quarter of 2017, Delphi unwound an interest rate swap on borrowings through bankers' acceptances in the amount of $30.0 million at a fixed interest rate of 0.63 percent for a gain of $53 thousand.

REVENUES

CRUDE OIL AND NATURAL GAS

	Three Months Ended December 31			Twelve Months Ended December 31		
	2017	2016	% Change	**2017**	2016	% Change
Natural gas	**11,025**	10,307	7	**42,866**	34,368	25
Natural gas physical contract gains (loss)	**-**	-	-	**-**	(120)	-
Field condensate	**14,023**	7,037	99	**42,475**	25,687	65
Natural gas liquids	**5,726**	3,146	82	**16,174**	8,931	81
Sulphur	**122**	56	118	**321**	269	19
Total	**30,896**	20,546	50	**101,836**	69,135	47

Delphi generated crude oil and natural gas revenues of $30.9 million in the fourth quarter of 2017, a 50 percent increase over the comparative period in 2016. The increase in revenues is primarily due to higher production volumes in combination with improved average sales prices (excluding gains on financial risk management contracts) for each commodity, with the exception of natural gas. The increase in volumes in the fourth quarter of 2017 from the fourth quarter of 2016 contributed to $7.9 million of the increase in revenues and the increase in the average realized price (excluding gains on financial risk management contracts) contributed to $2.4 million of the increase. For the fourth quarter of 2017, field condensate and natural gas liquids contributed 64 percent of the total crude oil and natural gas revenues compared to 50 percent in the same period in 2016.

During the twelve months of 2017, Delphi generated crude oil and natural gas revenues of $101.8 million, a 47 percent increase over the comparative period in 2016. The increase in crude oil and natural gas revenues is due to a 30 percent increase in the average realized sales price per boe (excluding gains on financial risk management contracts) in combination with higher production. The increase in the average realized sales price per boe (excluding gains on financial risk management contracts) accounted for $20.5 million of the increase in crude oil and natural gas revenues and the higher production volumes accounted for $12.2 million.

For the year ended December 31, 2017, field condensate and natural gas liquids contributed 58 percent of crude oil and natural gas revenues compared to 50 percent in the same period in 2016.

MARKETING

Delphi has contracted for approximately 45.8 mmcf/d of firm transportation service and 11.5 mmcf/d of priority interruptible service on the Alliance pipeline system from Alberta to Chicago. This service is comprised of various tranches commencing December 2015 through December 2017, with provisions to renew commencing October 2020. In order to mitigate the cost of transportation service in excess of its needs, Delphi either temporarily assigns the excess service to other shippers or purchases natural gas in Alberta for sale in Chicago. Delphi did not have any marketing income or expenses in 2016.

	Three Months Ended December 31			Twelve Months Ended December 31		
Marketing Revenue	**2017**	2016	% Change	**2017**	2016	% Change
Sale of purchased natural gas	**2,150**	-	-	**5,327**	-	-
Premiums on the assignment of service	**658**	-	-	**985**	-	-
Total	**2,808**	-		**6,312**	-	-

	Three Months Ended December 31			Twelve Months Ended December 31		
Marketing Expense	**2017**	2016	% Change	**2017**	2016	% Change
Cost of purchased natural gas	**653**	-	-	**2,813**	-	-
Transportation of purchased natural gas	**717**	-	-	**1,736**	-	-
Total	**1,370**			**4,549**	-	-

	Three Months Ended December 31			Twelve Months Ended December 31		
Marketing Income [(1)]	**2017**	2016	% Change	**2017**	2016	% Change
Gain (loss) on marketing of purchased natural gas	**780**	-	-	**778**	-	-
Premium on the assignment of service	**658**	-	-	**985**	-	-
Total	**1,438**	-	-	**1,763**	-	-
Per boe	**1.63**	-	-	**0.58**	-	

[(1)]Refer to non–GAAP measures

ROYALTIES

	Three Months Ended December 31			Twelve Months Ended December 31		
	2017	2016	% Change	**2017**	2016	% Change
Crown royalties	**1,375**	733	88	**4,875**	2,996	63
Royalty credits	**(723)**	(850)	(15)	**(2,857)**	(2,948)	(3)
Crown royalties – net	**652**	(117)	-	**2,018**	48	4,104
Gross overriding royalties	**1,341**	1,356	(1)	**5,197**	6,700	(22)
Total	**1,993**	1,239	61	**7,215**	6,748	7
Per boe	**2.26**	1.89	20	**2.35**	2.49	(6)

	Three Months Ended December 31			Twelve Months Ended December 31		
	2017	2016	% Change	**2017**	2016	% Change
Crown rate – before royalty credits	**4.5%**	3.6%	25	**4.8%**	4.3%	12
Crown rate – net of royalty credits	**2.1%**	(0.6)%	-	**2.0%**	0.1%	1,900
Gross overriding rate	**4.3%**	6.6%	(35)	**5.1%**	9.7%	(47)
Average rate	**6.4%**	6.0%	7	**7.1%**	9.8%	(28)

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

For the three and twelve months ended December 31, 2017, royalties totaled $2.0 million and $7.2 million, respectively, compared to $1.2 million and $6.7 million in the same periods in 2016. Crown royalties increased in the three and twelve months ended December 31, 2017 as a result of higher commodity prices, with the exception of natural gas in the fourth quarter of 2017, and production volumes in combination with a higher proportion of field condensate and natural gas liquids production. All of Delphi's 2017 wells qualify for Crown incentive programs under the Modern Royalty Framework which currently imposes a five percent royalty rate on all products until certain conditions are met. Production from wells drilled prior to 2017 are subject to different royalty incentive programs which impose a five percent royalty rate on all products until certain conditions are met and then provide for a zero percent royalty burden on field condensate until certain limitations set out in the framework are met. Crown royalties are expected to increase as Delphi's field condensate yields rise due to the liquids-rich wells Delphi continues to drill. Royalty credits, the cost of processing the Crown's share of natural gas production, decreased 15 percent and three percent in the three and twelve months ended December 31, 2017 compared to the same periods in 2016. The Crown royalty credits are largely based on the amortization of historical capital and operating costs of gas facilities and do not fluctuate based on commodity prices. Gross overriding royalties decreased in the three and twelve months of 2017 compared to the same periods in 2016 as production from wells encumbered with a gross overriding royalty decreased due to natural declines, partially offset by an increase in the combined realized sales price (before commodity price risk management).

For the three months ended December 31, 2017, Delphi's average royalty rate was 6.4 percent, an increase from the 6.0 percent during the comparative period in 2016. The increase is primarily due to higher Crown royalty credits in the fourth quarter of 2016 partially offset by a 35 percent decline in the average gross overriding royalty rate. Crown royalty rates before the consideration of Crown royalty credits increased 25 percent due to improved field condensate and natural gas liquids benchmark prices in combination with a higher average Crown royalty rate for the Company's field condensate production. The gross overriding royalty rate had decreased as additional sales volumes from wells brought on-stream are not encumbered by a gross overriding royalty.

For the twelve months ended December 31, 2017, Delphi's average royalty rate decreased to 7.1 percent compared to 9.8 percent for the comparative period in 2016. The decrease in the average royalty rate is due to reduced gross overriding royalties as additional sales volumes from wells brought on-stream are not encumbered by a gross overriding royalty. The Crown royalty rate before Crown royalty credits increased 12 percent in the twelve months ended December 31, 2017 as benchmark prices improved for all commodities in combination with a higher average Crown royalty rate for the Company's field condensate production.

OPERATING EXPENSES

	Three Months Ended December 31			Twelve Months Ended December 31		
	2017	2016	% Change	**2017**	2016	% Change
Production costs	**9,609**	7,198	33	**30,491**	24,104	26
Processing income	**(270)**	(920)	(71)	**(1,065)**	(3,269)	(67)
Total	**9,339**	6,278	49	**29,426**	20,835	41
Per boe	**10.59**	9.57	11	**9.60**	7.70	25

Production costs for the three and twelve months ended December 31, 2017 increased 33 percent and 26 percent in comparison to the same periods in 2016. Production costs for the twelve months ended December 31, 2016 include a $1.1 million recovery of third-party processing fees related to a prior period at Bigstone.

Operating costs associated with turnaround of the SemCAMS K3 natural gas processing facility are being charged out by SemCAMS over a 36 month period which commenced on January 1, 2017. The amount of the turnaround fee, which is based on production throughput, that is included in production costs for the three and twelve months ended December 31, 2017 are $0.3 million and $1.2 million, respectively.

Initial high rates of frac water flow back from wells brought on-stream exceeded the capacity of the Company's 65 percent owned disposal facility causing Delphi to truck produced water to third-party facilities located further away resulting in higher costs for water disposal. Road restrictions during the first and second quarters also increased the cost of water disposal as the Company was not able to haul at full capacity, thus increasing the number of trips required. In November of 2017, Delphi expanded the pumping capability and storage at its disposal facility to handle the additional water volumes. Disposal capacity was increased from 2,200 barrels per day ("bbls/d") to 6,000 bbls/d of water. The benefit of this cost reduction initiative is expected to be in full application in the first quarter of 2018.

Delphi has brought on-stream 15 (9.6 net) wells in 2017 versus six (4.6 net) wells in the comparative period of 2016. Fixed production costs associated with new wells are generally higher than for older wells during the first year of production.

Delphi earns processing income on partner production volumes going through facilities it owns. 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 decreased 71 percent and 67 percent in the three and twelve months ended December 31, 2017 as compared to the same periods in 2016, respectively. The decline in processing income is mainly due to the sale of a 35 percent working interest in the 7-11 Montney facility, 5-8 Montney facility and water disposal facility in the fourth quarter of 2016.

TRANSPORTATION EXPENSES

	Three Months Ended December 31			Twelve Months Ended December 31		
	2017	2016	% Change	**2017**	2016	% Change
Transportation	**4,073**	3,231	26	**17,379**	15,213	14
Transportation per boe	**4.62**	4.93	(6)	**5.67**	5.63	1

For the three and twelve months ended December 31, 2017, transportation expenses increased 26 percent and 14 percent in comparison to the same periods in 2016.

The increase in transportation for the fourth quarter of 2017 compared to the same period in 2016 is primarily due to higher natural gas transportation as the Company increased natural gas sales by 26 percent and its capacity commitment on the Alliance pipeline since the fourth quarter of 2016. Delphi mitigates its excess natural gas transportation by assigning it to a third party and collecting a premium for the assignment or by purchasing third party natural gas in Alberta and selling it at Chicago (see Marketing above for further details).

The 14 percent increase in transportation for the twelve months ended December 31, 2017 compared to 2016 is primarily due to additional trucking and natural gas liquids transportation. For part of 2016, the delivery point for a portion of the Company's natural gas liquids was at the inlet of the Pembina Peace HVP pipeline and therefore the pipeline tariffs were netted off of the sales price. In 2017, the delivery point for the majority of the Company's natural gas liquids was at the outlet of the Pembina Peace HPV pipeline. The Company obtained firm transportation for the majority of its natural gas liquids sale volumes in 2017 and the cost is included in transportation. Delphi expects the delivery point for the majority of natural gas liquids to remain at the outlet of the Pembina Peace HVP pipeline which will allow the Company to utilize committed pipeline capacity and avoid potential unfavourable interruptible service.

The Company trucks all of its field condensate to sales terminals. In 2017, trucking charges incurred increased as a result of higher field condensate volumes and higher trucking charges compared to 2016. Increased industry activity resulted in significant wait times at field condensate receiving terminals, increasing the cost per load and also causing the Company to truck its field condensate to terminals that were further away. In order to manage the field condensate trucking costs, Delphi obtained a dedicated delivery point in September of 2017 for its field condensate and re-bid trucking charges which has resulted in a decrease in trucking charges in the fourth quarter of 2017 in comparison to the third quarter of 2017.

GENERAL AND ADMINISTRATIVE

	Three Months Ended December 31			Twelve Months Ended December 31		
	2017	2016	% Change	**2017**	2016	% Change
Gross expenses	**1,752**	1,794	(2)	**9,094**	7,709	18
Capitalized	**(529)**	(633)	(16)	**(2,545)**	(2,267)	12
General and administrative expenses	**1,223**	1,161	5	**6,549**	5,442	20
Per boe	**1.39**	1.77	(21)	**2.14**	2.01	6

General and administrative expenses for the three and twelve months ended December 31, 2017 were five percent and 20 percent higher over the comparative periods in 2016, respectively. Gross expenses in the fourth quarter of 2017 are comparable to the fourth quarter of 2016. Gross expenses in 2017 are 18 percent higher than 2016 primarily due to employee termination payments and higher consulting costs.

On December 15, 2016, Delphi equalized an industry partner into certain working interests in its Bigstone cash generating unit which resulted in an increase of overhead recoveries from third parties in 2017. Commencing in 2017, Delphi is no longer applying third party recoveries to general and administration expenses. The third party recoveries are being applied against the activities that created the charge.

SHARE-BASED COMPENSATION

	Three Months Ended December 31			Twelve Months Ended December 31		
	2017	2016	% Change	**2017**	2016	% Change
Share-based compensation – Options	**400**	175	129	**1,481**	973	52
Share-based compensation – RSUs	**-**	79	-	**(39)**	244	(116)
Capitalized costs	**(114)**	(70)	63	**(457)**	(302)	51
Net	**286**	184	55	**985**	915	8
Per boe	**0.32**	0.28	14	**0.32**	0.34	(6)

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 for the three and twelve months ended December 31, 2017 as compared to the same periods in 2016, respectively. The increase in the expense is primarily due to the granting of 3.4 million options since the third quarter of 2016 with a weighted average fair value of $0.69 per option.

Share-based compensation expense related to the Company's RSUs decreased in the three and twelve months ended December 31, 2017 in comparison to the same periods in 2016, respectively. The decrease in the expense from the comparative periods is due to a lower closing share price used to calculate the fair value of the RSUs vested and paid out during the periods in combination with a decrease in the number of outstanding units. The last tranche of the remaining RSUs at the end of 2016 were fully vested and paid out during the third quarter of 2017.

Capitalized share-based compensation increased in the three and twelve months ended December 31, 2017 compared to the same periods in 2016 as a result of capitalized stock options related to the grant in the first quarter of 2017.

FINANCE COSTS

	Three Months Ended December 31			Twelve Months Ended December 31		
	2017	2016	% Change	**2017**	2016	% Change
Interest	**2,678**	2,436	10	**9,453**	8,364	13
Accretion of decommissioning liabilities	**98**	81	21	**382**	325	18
Finance charges	**442**	380	16	**1,647**	1,080	52
Total finance costs	**3,218**	2,897	11	**11,482**	9,769	17
Per boe	**3.65**	4.41	(17)	**3.74**	3.61	4

Interest charges on Delphi's bank debt and senior secured notes in the three and twelve months ended December 31, 2017 increased ten percent and 13 percent over the comparative periods in 2016. Although the Company's average bank debt and senior secured notes balance has decreased in 2017 in comparison to 2016, a greater portion of Delphi's debt is outstanding in the form of senior secured notes which bear an interest rate charge of ten percent in comparison to bank debt which was primarily subject to bankers' acceptance rates.

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 senior secured notes.

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 40 years. The increase in accretion expense in the three and twelve months ended December 31, 2017 compared to the same periods in 2016 is due to a higher decommissioning liability and higher risk free interest rates used to calculate the expense.

Finance charges include the amortization of transaction costs related to the issue of subordinated debt and senior secured notes and the accretion of the debt to its face value. The increase in finance charges in the three and twelve months ended December 31, 2017 over the comparative periods in 2016 is due to a higher balance of outstanding debt subject to amortization and accretion. Delphi issued an additional $30.0 million of senior secured notes during the second quarter of 2017.

DEPLETION AND DEPRECIATION

	Three Months Ended December 31			Twelve Months Ended December 31		
	2017	2016	% Change	**2017**	2016	% Change
Depletion and depreciation	**11,980**	6,890	74	**35,854**	30,284	18
Impairment loss	**-**	20,461	-	**-**	20,461	-
Total	**11,980**	27,351	(56)	**35,854**	50,745	(29)
Depletion and depreciation per boe	**13.58**	10.51	29	**11.69**	11.19	4
Impairment loss per boe	**-**	31.21	-	**-**	7.56	-

For the three and twelve months ended December 31, 2017, Delphi recorded depletion and depreciation of $12.0 million and $35.9 million compared to $6.9 million and $30.3 million for the three and twelve months ended December 31, 2016. The increase in depletion and depreciation reflects increased production over the comparative periods in combination with an increase in the depletion rate.

At December 31, 2017, Delphi evaluated its property, plant and equipment for indicators of any potential impairment or related reversal. As a result of these assessments, management determined that no impairment or impairment reversal calculation was required.

As at December 31, 2016, Delphi identified indicators of impairment, such as the continued weak commodity price environment and a reduction in property cash flows. As a result, the Company's Bigstone CGU, was tested for impairment. Delphi has recognized a $20.5 million impairment based on the difference between the year-end carrying value and the CGU's estimated recoverable amount. The impairment was associated with lower future cash flows on the proved and probable reserves on wells drilled in prior years. The fair value less costs to sell included the expected future cash flows of proved and probable reserves using pre-tax discount rate of approximately eleven percent plus an estimate of the fair value of the undeveloped land associated with the CGU reserves.

INCOME TAXES

	Three Months Ended December 31			Twelve Months Ended December 31		
	2017	2016	% Change	**2017**	2016	% Change
Deferred income taxes recovery	**-**	-	-	**-**	(1,132)	-
Per boe	**-**	-	-	**-**	(0.42)	-

Delphi has concluded that it is not probable that the deferred income tax asset will be realized and as a result, it has not been recognized at December 31, 2017. Therefore, no deferred income tax expense was recorded against earnings for the year ended December 31, 2017.

Delphi does not have current income taxes payable and has estimated tax pools available at December 31, 2017 of $393.6 million (December 31, 2016 – $311.0 million).

ADJUSTED FUNDS FLOW

	Three Months Ended December 31			Twelve Months Ended December 31		
	2017	2016	% Change	**2017**	2016	% Change
Cash flow from operating activities	**9,490**	7,635	24	**31,044**	30,529	2
Change in non-cash working capital	**3,793**	250	1,417	**2,459**	(2,055)	-
Funds flow	**13,283**	7,885	68	**33,503**	28,474	18
Decommissioning expenditures	**861**	235	266	**3,167**	1,391	128
Adjusted funds flow(1)	**14,144**	8,120	74	**36,670**	29,865	23

(1) Refer to non–GAAP measures

Delphi's cash flow from operating activities increased 24 percent in the fourth quarter of 2017 compared to 2016. Adjusted funds flow increased 74 percent over the same comparative period primarily due to higher production in combination with increased average realized sales prices and marketing income. Increased royalties, operating, transportation and finance costs partially offset the increase in cash flow from operating activities and adjusted funds flow.

For the twelve months ended December 31, 2017, cash flow from operating activities increased two percent in comparison to the same period in 2016. Adjusted funds flow increased 23 percent over the same comparative period as realized prices and higher production volumes contributed to higher revenues and the Company generated marketing income from gas transportation mitigation activities. The increase in funds flow was partially offset by higher operating, transportation, general and administrative and interest expenses.

CASH NETBACK AND EARNINGS ANALYSIS

	Three Months Ended December 31			Twelve Months Ended December 31		
	2017	2016	% Change	**2017**	2016	% Change
Net earnings (loss)	**(1,764)**	(25,461)	93	**6,902**	(41,114)	117
Per boe	**(2.01)**	(38.83)	95	**2.27**	(15.21)	-
Per basic and diluted share	**(0.01)**	(0.16)	94	**0.04**	(0.26)	115

Delphi recorded a net loss of $1.8 million ($0.01 per basic and diluted share) in the fourth quarter of 2017, down from the $25.5 million net loss in the fourth quarter of 2016. The decrease in net loss is primarily due to the increase in adjusted funds flow and a decrease in impairment charges partially offset by lower gains on dispositions, greater losses on decommissioning and a loss recognized on the unutilized take-or-pay contract. During the fourth quarter of 2017, Delphi recognized a $1.5 million loss on an unutilized take-or-pay contract related to a field condensate receiving terminal.

Delphi recorded net earnings of $6.9 million ($0.04 per basic and diluted share) in the twelve months ended December 31, 2017, up from the $41.1 million net loss in the comparative period in 2016. The increase in net earnings is primarily due to the increase in adjusted funds flow, an unrealized gain on risk management contracts and a decrease in impairment charges, partially offset by lower gains on asset dispositions, a higher loss on decommissioning expenditures and a loss recognized on the unutilized take-or-pay contract.

	Three Months Ended December 31			Twelve Months Ended December 31		
Barrels of oil equivalent ($/boe)	**2017**	2016	% Change	**2017**	2016	% Change
Realized sales price	**35.03**	31.33	12	**33.22**	25.55	30
Marketing income (1)	**1.63**	-	-	**0.58**	-	-
Royalties	**(2.26)**	(1.89)	20	**(2.35)**	(2.49)	(6)
Operating expenses	**(10.59)**	(9.57)	11	**(9.60)**	(7.70)	25
Transportation	**(4.62)**	(4.93)	(6)	**(5.67)**	(5.63)	1
Operating netback before risk management contracts (1)	**19.19**	14.94	28	**16.18**	9.73	66
Realized gain on risk management contracts	**1.25**	2.93	(57)	**1.00**	6.51	(85)
Operating netback (1)	**20.44**	17.87	14	**17.18**	16.24	6
General and administrative expenses	**(1.39)**	(1.77)	(21)	**(2.14)**	(2.01)	6
Paid out restricted share units	**-**	-	-	**-**	(0.11)	-
Interest	**(3.02)**	(3.72)	(19)	**(3.08)**	(3.09)	-
Cash netback (1)	**16.03**	12.38	29	**11.96**	11.03	8
Unrealized gain (loss) on risk management contracts	**(3.83)**	(19.68)	(81)	**3.23**	(10.17)	(132)
Share-based compensation expense	**(0.32)**	(0.28)	15	**(0.32)**	(0.23)	39
Gain on dispositions	**2.62**	11.26	(77)	**0.84**	3.38	(75)
Exploration and evaluation	**-**	(0.01)	-	**-**	(0.20)	-
Loss on decommissioning	**(0.59)**	(0.11)	(436)	**(0.60)**	(0.16)	275
Onerous contract	**(1.71)**	-	-	**(0.49)**	-	-
Depletion and depreciation	**(13.58)**	(41.72)	(67)	**(11.69)**	(18.76)	(38)
Non-cash finance charges	**(0.63)**	(0.70)	(10)	**(0.66)**	(0.52)	27
Deferred income taxes	**-**	-	-	**-**	0.42	-
Net earnings (loss)	**(2.01)**	(38.86)	95	**2.27**	(15.21)	-

(1) Refer to non–GAAP measures

Delphi continues to focus its drilling on high margin, liquids-rich natural gas prospects in order to strengthen its operating and cash netback per boe.

Delphi's cash netback per boe for the three and twelve months ended December 31, 2017 increased 29 percent and eight percent compared to the same periods in 2016. The increase in the cash netback per boe is largely attributed to higher realized sales prices and a marketing gain.

LIQUIDITY AND CAPITAL RESOURCES

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. The Company's financial liabilities arise through the cost of operations and the capital program in order to maintain or increase production and develop reserves, the acquisition of crude oil and natural gas assets, financial instrument contracts, issuance of senior secured notes and borrowings under the Company's credit facilities.

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 financings, equity financings or cash generated from operations will be available or sufficient to meet these or other corporate requirements. If debt or equity financing is available, there is no assurance 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 continues to result in a challenging environment for the energy sector. In the fourth quarter of 2016, Delphi entered into a strategic agreement with an industry partner which equalized the partner into certain working interests in the Bigstone area for $34.6 million in proceeds and a carry capital program where our partner contributed $20.0 million for drilling and completion costs.

On June 7, 2017, through a private placement, Delphi raised $65.0 million in proceeds that were comprised of 27.6 million common shares at a price of $1.27 and $30.0 million of senior secured notes. Delphi used a portion of the proceeds to repay bank debt. Delphi continuously monitors commodity prices and 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.

Net Debt

	December 31, 2017	December 31, 2016
Long term debt	**26,878**	24,987
Senior secured notes (1)	**83,642**	52,929
Long term portion of unutilized take-or-pay contract	**867**	-
Working capital deficiency	**25,034**	8,029
Net debt(2)(3)	**136,421**	85,945

(1) $90.0 million maturity value for senior secured notes outstanding as at December 31, 2017.
(2) Net debt excludes $7.3 million and $6.5 million as at December 31, 2017 and December 31, 2016, respectively, of outstanding letters of credit
(3) Refer to non-GAAP measures

As at December 31, 2017, Delphi had $26.9 million outstanding in bank debt, $83.6 million in senior secured notes, $0.9 million in the long term portion of an unutilized take-or-pay contract and a working capital deficit of $25.0 million for net debt of $136.4 million. As at December 31, 2017, Delphi had $60.8 million (net of outstanding letters of credit) available to be drawn on the senior credit facility.

Senior Credit Facility

In January 2017, Delphi entered into a new $80.0 million senior secured revolving credit facility with a syndicate of Canadian chartered banks.

During the fourth quarter of 2017, Delphi's lenders completed the semi-annual review of the Company's senior credit facility and increased the borrowing base to $95.0 million. The facility is a 364 day committed facility available on a revolving basis until May 29, 2018 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 would be required to be repaid at the end of the non-revolving term being May 30, 2019. 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 or LIBOR 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 earnings before interest, taxes, depreciation and amortization ratio: from a minimum of the bank's prime rate or U.S. base rate plus 1.0 percent to a maximum of the bank's prime rate or U.S. base rate plus 3.0 percent or from a minimum of bankers' acceptances or LIBOR rate plus a stamping fee of 2.0 percent to a maximum of bankers' acceptances rate plus a stamping fee of 4.0 percent.

The senior credit facility is secured by a $200.0 million demand floating charge debenture and a general security agreement over all assets of the Company.

The borrowing base of the senior credit facility is subject to the banks' semi-annual review of the Company's crude oil and natural gas properties. The annual review will be completed by May 29, 2018. The borrowing base of the facilities will be based on the lenders' evaluation of the Company's petroleum and natural gas reserves at the 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 senior credit facility is subject to the following financial covenants:

Financial covenant	**Requirement**	**As at December 31, 2017**
Adjusted working capital ratio	≥ 1.0	1.5
Adjusted bank debt to EBITDA ratio	≤ 3.0	0.7
Adjusted debt to EBITDA ratio	≤ 4.0	2.2

Adjusted working capital ratio (1)	**As at December 31,2017**
Current assets	50,385
Exclusion of the current fair value of financial instruments	(1,043)
Undrawn portion of senior credit facility	60,830
	110,172
Current liabilities	75,449
Exclusion of the current fair value of financial instruments	(1,073)
	74,376
Adjusted working capital ratio	1.5

(1) Refer to non-GAAP measures

Adjusted bank debt to EBITDA ratio (1)	**As at December 31, 2017**
Bank debt	26,878
Unutilized take-or-pay contract	1,504
Outstanding letters of credit	7,292
Adjusted bank debt	35,674
Annualized EBITDA	54,646
Adjusted bank debt to EBITDA ratio	0.7

(1) Refer to non-GAAP measures

Adjusted debt to EBITDA ratio (1)	**As at December 31, 2017**
Bank debt	26,878
Unutilized take-or-pay contract	1,504
Outstanding letters of credit	7,292
Senior secured notes	83,642
Adjusted debt	119,317
Annualized EBITDA	54,646
Adjusted debt to EBITDA ratio	2.2

(1) Refer to non-GAAP measures

Delphi was in compliance with all covenants as at December 31, 2017.

Senior Secured Notes

	Senior Secured Notes
Balance as at December 31, 2016	**52,929**
Issue of senior secured notes, net of discount	**29,876**
Issue costs	**(810)**
Accretion of discount and amortization of issue costs	**1,647**
Balance, end of year	**83,642**

On June 15, 2016, Delphi issued $60.0 million of 10 percent senior secured notes with attached warrants. The Company issued 60 thousand units with each unit consisting of a $1,000 note and 245 warrants. On June 7, 2017, Delphi issued an additional $30.0 million of senior secured notes through a private placement. The senior secured notes have a face value of $1,000 each and were issued at a discount to par. The senior secured notes mature on July 15, 2021. Interest is payable quarterly to the holders of record on the immediately preceding April 1, July 1, October 1 and January 1. The senior secured notes are redeemable at the Company's option, in whole or part during the twelve month period beginning on June 15 of the years indicated at the following specified redemption prices (expressed as a percentage of the principal amount): 2018 at 107.50 percent, 2019 at 105.00 percent and 2020 and thereafter at 100.00 percent. Prior to June 15, 2018, Delphi has the option to redeem up to 50 percent of the senior secured notes at a redemption price of 110.00 percent plus accrued interest with an amount of cash not greater than the net cash proceeds of certain equity offerings.

The senior secured notes are secured on a second-priority basis by substantially all of the Company's assets and are subordinate to indebtedness under the senior credit facility.

The senior secured notes are presented net of debt issue costs of $4.2 million and will be accreted at an effective interest rate of 12.1 percent such that the carrying amount of the senior secured notes will equal the principal amount at maturity. The senior secured notes that were issued with warrants were initially recognized at fair value based on similar debt securities without the warrant feature, net of debt issue costs and subsequently are carried at amortized cost. The principal amount of the senior secured notes less the initial fair value has been allocated to the warrants. The senior secured notes issued on June 7, 2017 were initially recognized at fair value, net of issue costs and subsequently are carried at amortized cost.

The senior secured notes have no financial covenants but have an incurrence covenant in place that limits the Company's ability to among other things (subject to certain exceptions, limitations and qualifications): make certain restricted payments and investments; incur additional debt; create liens; restrict dividends or other payments; consolidate, merge sell, or otherwise dispose of all or substantially all of its assets; and enter into certain transactions with affiliates.

Share Capital

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, 2017:

	Three Months Ended December 31, 2017	Twelve Months Ended December 31, 2017
Weighted Average Common Shares (in thousands)		
Basic	185,472	173,171
Diluted	185,472	173,975
Trading Statistics (1)		
High	1.33	1.74
Low	1.05	1.03
Average daily volume (in thousands)	203	244

(1) Trading statistics based on closing price

As at December 31, 2017, the Company had 185.5 million common shares outstanding, 9.6 million stock options outstanding, and 14.7 million warrants outstanding. The stock options have an average exercise price of $1.56 per option and the warrants have an exercise price of $1.40 per warrant.

CONTRACTUAL OBLIGATIONS

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 364 day non-revolving term facility if not renewed. The senior secured notes mature in 2021 as discussed in the Liquidity and Capital Resources section.

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

	2018	2019	2020	2021	Thereafter
Gathering, processing and transmission [1]	23,554	21,644	18,219	1,354	5,755
Office, equipment and software leases	516	445	450	457	1,226
Accounts payable and accrued liabilities	73,325	-	-	-	-
Unutilized take or pay	660	672	225	-	-
Risk Management	1,073	-	-	-	-
Decommissioning obligations [2]	414	224	5,184	1,045	19,004
Interest payments on senior secured notes	9,000	9,000	9,000	4,875	-
Bank Debt	-	27,000	-	-	-
Senior secured notes	-	-	-	90,000	-
Total	108,542	58,985	33,078	97,731	25,985

(1) *Balances denominated in U.S. dollars have been translated at the December 31, 2017 exchange rate.*

(2) *Amounts represent the inflated, discounted future abandonment and reclamation expenditures anticipated to be incurred over the life of the Company's properties*.

GUARANTEES AND OFF-BALANCE SHEET ARRANGEMENTS

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.

SELECTED INFORMATION

The following table sets forth selected consolidated financial information of the Company for the most recently completed year ended December 31, 2017 and for the years ended 2016 and 2015:

	2017	2016	2015
Crude oil and natural gas sales	**101,836**	69,135	80,275
Net earnings (loss)	**6,902**	(41,114)	(42,525)
Per share – basic and diluted	**0.04**	(0.26)	(0.27)
Total assets	**409,522**	303,625	360,842
Net debt	**136,421**	85,945	121,664

The following table summarizes the Company's financial and operating results over the past eight quarters:

	Dec. 31, 2017	Sep. 30, 2017	Jun. 30, 2017	Mar. 31, 2017	Dec. 31, 2016	Sep. 30, 2016	Jun. 30, 2016	Mar. 31, 2016
Production								
(boe conversion – 6:1 basis)								
Field condensate (bbls/d)	**2,374**	2,012	1,540	1,940	1,338	1,667	1,060	1,704
Natural gas liquids (bbls/d)	**1,315**	1,367	1,019	1,302	1,125	1,251	1,023	1,336
Natural gas (mcf/d)	**35,391**	35,603	23,551	29,737	27,988	31,923	22,311	32,127
Barrels of oil equivalent (boe/d)	**9,588**	9,313	6,484	8,198	7,127	8,239	5,802	8,395
Financial								
($ thousands, except per share)								
Crude oil and natural gas sales	**30,896**	25,107	20,162	25,671	20,546	20,331	10,942	17,316
Adjusted funds flow(1)	**14,144**	7,595	6,964	7,967	8,120	9,403	4,152	8,190
Per share – basic and diluted(1)	**0.08**	0.04	0.04	0.05	0.05	0.06	0.03	0.05
Net earnings (loss)	**(1,764)**	(4,010)	4,520	8,156	(25,461)	(2,274)	(18,638)	5,259
Per share – basic and diluted	**(0.01)**	(0.02)	0.03	0.05	(0.16)	(0.01)	(0.12)	0.03

(1) Refer to non-GAAP measures

Over the past two years, the changes in revenue and adjusted funds flow from quarter to quarter primarily reflect the change in production and the volatility of commodity prices. Delphi's commodity risk management program continues to be an integral part of the Company's strategy to protect cash flows through simple payout of the drilling and completions portion of its capital program.

In 2016, the Company took a conservative approach in capital spending, investing $53.8 million and drilling six (4.2 net) wells. In the fourth quarter of 2016, Delphi entered into a partner transaction with an existing working interest industry partner to accelerate the development of Delphi's liquids rich Deep Basin natural gas play at Bigstone for $34.6 million in proceeds and a carry capital program where the partner contributed $20.0 million for drilling and completion costs.

During the second quarter of 2016, Delphi issued $60.0 million of senior secured notes and applied the proceeds from the senior secured notes issue against its senior credit facility and repaid the subordinated debt balance of $14.2 million.

In 2017, the Company closed a private placement financing that was comprised of 27,559,055 common shares issued at a price of $1.27 per common share and 30,000 senior secured notes, each with a principal amount of $1,000 and a 10% coupon, for gross proceeds of $65.0 million. Delphi used a portion of the proceeds to repay outstanding bank debt.

The Company's capital program in 2017 consisted of the drilling of 17 (11.0 net) wells and investment in the Company's infrastructure. The average production for the fourth quarter of 2017 increased to 9,588 boe/d, up 35 percent from the 7,127 boe/d produced in the comparative quarter of 2016.

During the fourth quarter of 2017, Delphi's lenders completed the semi-annual review of the Company's senior credit facility and increased the borrowing base from $80.0 million to $95.0 million.

CRITICAL ACCOUNTING ESTIMATES

The consolidated financial statements have been prepared in accordance 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) 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 salvage value of production equipment and facilities after the proved and probable reserves are fully produced.

ii) 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.

Management applies judgment in assessing the existence of indicators of impairment and impairment recovery based on various internal and external factors. 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.

In estimating the recoverable amount of a CGU, the following information is incorporated:

- 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 fluctuate widely due to global and regional factors including supply and demand fundamentals, inventory levels, exchange rates, weather, economic and geopolitical factors.
- Discount rate – Estimated future cash flows are discounted to their present value using a discount rate that reflects current market assessments of the time value of money and the risks specific to the asset. Changes in the general economic environment could result in significant changes to this estimate.

iii) 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.

iv) 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.

v) 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 net earnings (loss).

NEW ACCOUNTING STANDARDS

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 has a current effective date of January 1, 2018.

Delphi will transition to IFRS 15 on January 1, 2018 using the cumulative effect method. The Company has completed a significant portion of their review of revenue streams and contracts with customers. Adopting IFRS 15 is not expected to have a material impact on the amount or timing of revenue recognition in the Company's consolidated financial statements. There will be additional disclosures in the notes to the consolidated financial statements as required by IFRS 15, including disaggregated revenue streams by product type.

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. Adopting IFRS 9 is not expected to have a material impact.

The IASB has issued IFRS 16, "Leases", which replaces the previous leases standard, IAS 17, "Leases.". The new standard sets out the principles for the recognition, measurement, presentation and disclosure of leases and brings most leases on-balance sheet for lessees under a single model, eliminating the distinction between operating and finance leases. The standard is effective from January 1, 2019. Early adoption is permitted but only if the Company also applies IFRS 15, "Revenue from Contracts with Customers." Delphi does not expect to early adopt the new standard and the extent of the impact of adoption of the standard has not yet been determined.

The IASB issued amendments to IFRS 2 "Share-based Payment" to be applied prospectively for annual periods beginning on or after January 1, 2018 with early adoption permitted. The amendments clarify how to account for certain types of share-based payment transactions. The Company is currently assessing the impact of the adoption of the amendments on the Company's consolidated financial statements. Adopting the amendment is not expected to have a material impact.

CORPORATE GOVERNANCE

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 eight independent directors and one officer 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, as defined in NI 52-109, 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 Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure. The President and Chief Executive Officer and Chief Financial Officer have designed, or caused to be designed under their supervision, internal controls over financial reporting, as defined in NI 52-109, to provide reasonable assurance regarding the reliability of the Company's financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles applicable to the Company. The President and Chief Executive Officer and Chief Financial Officer have concluded that the Company's internal controls over financial reporting and disclosure controls and procedures are effective. The Company's internal controls over financial reporting is based on the framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 Framework).

The Company is required to disclose any change in the Company's internal control over financial reporting that occurred during the period beginning on October 1, 2017 and ended on December 31, 2017 that has materially affected, or is reasonably likely to materially affect, the Company's internal control over financial reporting. No material changes in the

Company's internal control over financial reporting were identified during such period that has materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting.

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

2018 OUTLOOK

Delphi continued its two-rig winter drilling program and finished the drilling of four wells in the first quarter of 2018. Along with three drilled, uncompleted wells from 2017, this gives the Company up to seven wells to complete and bring on production in the first half of 2018 and into the summer. Drilling operations have now been paused until after spring breakup. Capital spending post spring breakup is contemplated to be in line with adjusted funds flow.

Production

Subject to the timing and duration of spring breakup and therefore the timing of completions, production in the first half of 2018 is expected to average approximately 10,000 boe/d and to be comprised of approximately 40 percent liquids and 60 percent natural gas on a boe basis.

Royalties

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

Delphi pays a gross overriding royalty ("GORR") of between ten and twelve percent on 20 of its Montney wells drilled between April 2013 and January 2016. Production from these wells accounted for about 35 percent of total corporate production at the end of 2017. As production from these wells decreases due to natural declines and new wells are brought on-stream, the proportion of wells and production subject to the GORR will decrease and serve to reduce the overall corporate royalty rate. Delphi does not expect any material change in the Crown royalty rate it will pay in 2018.

For 2018, Delphi expects its royalty rate, after the deduction of royalty credits and inclusion of GORRs, to average between six and eight percent of gross revenue, excluding realized and unrealized gains or losses on commodity risk management contracts.

Transportation expenses

The contracted rates for transportation of natural gas and natural gas liquids are unchanged in 2018, though the level of utilization of take-or-pay commitments and the addition of 20 mmcf/d of firm service on the NGTL pipeline in April 2018 will impact the per unit cost of transportation. The commencement of condensate deliveries to a dedicated delivery point in September 2017 is expected to lower the cost of condensate transportation in 2018. Overall the cost of transportation in 2018 on a boe basis is expected to be consistent with 2017 and to be in the range of $5.50 to $6.10 per boe.

Operating expenses

Operating costs in 2017 were $9.60 per boe which reflected the impact of several factors which are not expected to occur in 2018, in particular the negative impact on production of the 36 day turnaround of the SemCAMS K3 natural gas processing plant, and the high costs of disposal of frac load water from new wells put on production during spring break up.

Delphi undertook various projects in 2017 which are expected to lower operating costs including installation of a 17 mmcf/d amine plant to be completed by the second quarter of 2018 which will allow the Company to deliver a portion of its Montney production to the sweet Bigstone plant where Delphi owns a 25 percent working interest and avoid third-party processing charges, as well as the expansion of its water disposal facility completed in November 2017.

Delphi expects operating costs in 2018 to be between $8.50 and $9.25 per boe.

General and administrative and finance costs

Delphi's general and administrative costs per boe in 2017 were $2.14, however, these costs included employee severance and consulting and recruiting costs in the first half which are not expected to reoccur in 2018. With other general and administrative costs expected to be relatively stable, Delphi expects general and administrative costs, net of capitalized amounts, in 2018 to be approximately $1.65 to $1.90 per boe.

Interest expense in 2018 is expected to be approximately $3.30 to $3.60 per boe.

NON GAAP MEASURES

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:

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.

Adjusted bank debt to EBITDA ratio – Adjusted bank debt is defined as amounts outstanding under the senior credit facility, including outstanding letters of credit. EBITDA is calculated based on the terms and definitions set out in the senior credit facility agreement which adjusts net income (loss) for financing costs, certain specific unrealized and non-cash transactions and acquisition and disposition activity. EBITDA is calculated on an annualized basis based on the last two completed quarters. This ratio is used to calculate the Company's compliance with its adjusted bank debt to EBITDA ratio.

Adjusted debt to EBITDA ratio - The calculation of adjusted debt excludes accounts payable and accrued liabilities, decommissioning obligations and the fair value of financial instruments. The calculation includes outstanding letters of credit, the senior credit facility and senior secured notes. EBITDA is calculated as defined above. This ratio is used to calculate the Company's compliance with its adjusted debt to EBITDA ratio.

Adjusted funds flow - cash flow from operating activities before decommissioning expenditures and changes in non-cash working capital from operating activities. Management uses adjusted funds flow to analyze performance and considers it a key measure as it demonstrates the Company's ability to generate the cash necessary to fund future capital investments, abandonment obligations and to repay debt. Delphi's determination of adjusted funds flow 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.

Adjusted funds flow per share – adjusted funds flow 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, less outstanding letters of credit, and exclude the current portion of the fair value of financial instruments. Current liabilities exclude the current portion of long term 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.

Marketing income - the margin earned on the sale of purchased third party natural gas volumes and premiums received on the assignment of a portion of committed capacity on the Alliance pipeline system to a third party. Management considers marketing income important measures of the Company's ability to mitigate the cost of excess committed capacity.

Net debt – the sum of bank debt, senior secured notes and the long term portion of unutilized take-or-pay contract 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 and marketing income 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 bank debt and senior secured notes, 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.

FORWARD-LOOKING STATEMENTS

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, estimated tax pools and expectations regarding current income taxes payable by Delphi in 2017, 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, the availability of capital, 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.

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. This financial outlook is included to provide readers with an understanding of the Company’s operations for 2017 and 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 risks, environmental risks, competition from others for scarce resources, the inability to access sufficient capital from internal and external sources, adverse changes in governmental regulation of the oil and gas industry and adverse 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.