FINANCIAL HIGHLIGHTS

(000's except per share and per unit amounts)	2016	Three months ended December 31, 2015	% Change	2016	Twelve months ended December 31, 2015	% Change
FINANCIAL						
Total revenue [1]	**17,253**	16,112	7	**59,074**	80,891	(27)
Comprehensive loss	**(9,077)**	(146,585)	(94)	**(28,057)**	(250,072)	(89)
Per share – basic and diluted	**(0.04)**	(0.69)	(94)	**(0.13)**	(1.19)	(89)
Funds flow from operations [2] [5]	**6,625**	4,874	36	**11,250**	25,578	(56)
Per share, basic and diluted	**0.03**	0.02	50	**0.05**	0.12	(58)
Capital expenditures, before acquisitions (dispositions)	**11,460**	15,175	(24)	**22,590**	62,261	(64)
Capital expenditures, including acquisitions (dispositions)	**11,406**	16,351	(30)	**17,296**	18,560	(7)
Net debt [3] [6]	**(64,031)**	(65,447)	(2)	**(64,031)**	(65,447)	(2)
Weighted average shares outstanding - basic and diluted	**235,028**	211,028	11	**217,061**	211,028	3
OPERATING						
Production volumes						
Natural gas (Mcf/d)	**45,005**	41,794	8	**45,442**	47,589	(5)
Crude oil (bbls/d)	**140**	225	(38)	**177**	160	11
Natural gas liquids (bbls/d)	**209**	300	(30)	**237**	475	(50)
Condensate (bbls/d)	**760**	723	5	**841**	918	(8)
Total (boe/d)	**8,609**	8,213	5	**8,826**	9,485	(7)
Sales prices						
Natural gas, including realized hedges ($/Mcf)	**2.92**	2.89	1	**2.27**	3.27	(31)
Crude oil and condensate, including realized hedges ($/bbl)	**56.27**	52.32	8	**52.17**	53.78	(3)
Natural gas liquids ($/bbl)	**25.61**	16.45	56	**21.94**	17.04	29
Total ($/boe)	**21.78**	21.32	2	**18.29**	23.37	(22)
Netback ($/boe)						
Price, including realized hedges	**21.78**	21.32	2	**18.29**	23.37	(22)
Royalties	**(0.59)**	0.67	188	**(0.48)**	(0.84)	(43)
Transportation	**(1.45)**	(1.77)	(18)	**(1.24)**	(1.83)	(32)
Operating costs	**(7.81)**	(9.30)	(16)	**(8.49)**	(9.17)	(7)
Operating netback	**11.93**	10.92	9	**8.08**	11.53	(30)
General and administrative [5]	**(1.81)**	(2.65)	(32)	**(2.77)**	(2.30)	20
Interest [4]	**(1.92)**	(2.15)	(11)	**(1.93)**	(1.96)	(2)
Cash netback	**8.20**	6.12	34	**3.38**	7.27	(54)

(1) Total revenue is presented gross of royalties and includes realized gains (loss) on commodity contracts.

(2) Funds flow from operations is calculated as cash flow from operating activities before adjustments for decommissioning liabilities expenditures and net changes in non-cash working capital.

(3) Net debt is calculated as working capital (deficiency) less the principal value of senior notes.

(4) Represents finance costs less amortization on transaction costs and accretion expense on senior notes and provisions.

(5) For the three and twelve months ended December 31, 2016, general and administrative expenses and funds flow from operations includes $nil ($nil/boe) and $2,341 ($0.72/ boe) in restructuring charges, respectively.

(6) Prior period amounts have been adjusted to confirm to current period presentation.

MANAGEMENT'S DISCUSSION AND ANALYSIS

This Management's Discussion and Analysis ("MD&A") of the financial and operating results of Cequence Energy Ltd. ("Cequence" or the "Company") should be read in conjunction with the Company's audited consolidated financial statements (the "annual financial statements") and related notes for the years ended December 31, 2016 and 2015.

Additional information relating to the Company, including its MD&A for the prior year and the annual information form is available on SEDAR at www.sedar.com.

This MD&A is dated March 13, 2017.

BASIS OF PRESENTATION

The Financial Statements and comparative information have been prepared in accordance with International Financial Reporting Standards ("IFRS").

The reporting and the measurement currency is the Canadian dollar. For the purpose of calculating unit costs, natural gas is converted to a barrel of oil equivalent ("boe") using six thousand cubic feet of natural gas equal to one barrel of oil unless otherwise stated. The term barrel of oil equivalent (boe) may be misleading, particularly if used in isolation. A boe conversion ratio for gas of 6 Mcf:1 boe is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

For fiscal 2016 the ratio between the average price of West Texas Intermediate ("WTI") crude oil at Cushing and NYMEX natural gas was approximately 17:1 ("Value Ratio"). The Value Ratio is obtained using the 2016 WTI average price of $43.34 (US$/Bbl) for crude oil and the 2016 NYMEX average price of $2.55 (US$/MMbtu) for natural gas. This Value Ratio is significantly different from the energy equivalency ratio of 6:1 and using a 6:1 ratio would be misleading as an indication of value.

Unless otherwise stated and other than per unit items, all figures are presented in thousands.

NON-GAAP MEASUREMENTS

Within the MD&A references are made to terms commonly used in the oil and gas industry, including operating netback, cash netback, net debt, funds flow from (used in) operations and total revenue.

Operating netback is not defined by IFRS in Canada and is referred to as a non-GAAP measure. Operating netback equals per boe revenue less royalties, operating costs and transportation costs. Management utilizes this measure to analyze operating performance of its assets and operating areas, compare results to peers and to evaluate drilling prospects.

Cash netback is not defined by IFRS in Canada and is referred to as a non-GAAP measure. Cash netback equals operating netback less per boe general and administrative expenses and interest expense. Management utilizes this measure to analyze the Company's per boe profitability for future capital investment or repayment of debt after considering cash costs not specifically attributable to its assets or operating areas.

Net debt is a non-GAAP measure that is calculated as working capital (deficiency) less the principal value of senior notes. For this calculation, Cequence uses the principal value of the senior notes rather than the carrying value on the statement of financial position as it reflects the amount that will be repaid upon maturity. Cequence uses net debt as it provides an estimate of the Company's assets and obligations expected to be settled in cash.

Funds flow from (used in) operations is a non-GAAP term that represents cash flow from operating activities before adjustments for decommissioning liabilities expenditures and net changes in non-cash working capital. The Company evaluates its performance based on earnings and funds flow from (used in) operations. The Company considers funds flow from (used in) operations a key measure as it demonstrates the Company's ability to generate the cash flow necessary to fund future growth through capital investment and to repay debt. The Company's calculation of funds flow from (used in) operations may not be comparable to that reported by other companies. Funds flow from (used in) operations per share is calculated using the same weighted average number of shares outstanding used in the calculation of comprehensive income (loss) per share.

Total revenue equals production revenue gross of royalties and including realized gain (loss) on commodity contracts. Management utilizes this measure to analyze revenue and commodity pricing and its impact on operating performance.

Non-GAAP financial measures do not have a standardized meaning prescribed by IFRS and are therefore unlikely to be comparable to similar measures presented by other issuers.

DESCRIPTION OF THE BUSINESS

Cequence is engaged in the exploration for and the development of oil and natural gas reserves. Cequence's primary focus is the development of its Simonette asset in the Alberta Deep Basin. The Company also has assets in Northeast British Columbia and the Peace River Arch of Alberta. The common shares of Cequence trade on the Toronto Stock Exchange under the symbol CQE.

2016 was a challenging year for natural gas prices as AECO averaged $2.18/mcf, representing the lowest annual average natural gas price in over 10 years. The Company responded by reducing capital expenditures, periodically curtailing uneconomic production, and pursuing initiatives to reduce both operating and general and administrative expenses. Through the reduction of staff and office space, as well as other cost-saving initiatives, the Company achieved a 22 percent reduction in general and administrative expenses in 2016 as compared to 2015. Cequence undertook a number of operating cost efficiency projects at Simonette, resulting in a decrease of 7 percent in operating expenses compared to 2015 field costs.

Capital expenditures, prior to dispositions, were $22,590 in 2016 a decrease of 64 percent from 2015. Expenditures were focused on the Company's primary development property at Simonette. In the first quarter, the Simonette gas plant (50% working interest) was completed which is expected to provide the Company with improved long term market access for its natural gas production. In addition, Cequence completed one Montney well (16-33) at Simonette in the first quarter using a new well design that included a longer lateral and increased frac stages. Results of the well are encouraging and production data for the first 10 months has demonstrated increased gas and condensate recoveries compared to the Company's average historical results.

As commodity prices improved, the Company raised $10 million in the fourth quarter through the issuance of flow-through common shares and started a drilling program that includes 4 gross (3 net) development wells to be drilled at Simonette. The winter drilling program includes two Montney wells (100% working interest) to follow up the successful 16-33 well. If successful, the new Montney wells, will support improved well performance and economics observed in the 16-33 well. The Company expects initial results from these wells in the first half of 2017.

FINANCIAL AND OPERATING RESULTS

PRODUCTION

	Three months ended December 31,		Twelve months ended December 31,	
	2016	2015	**2016**	2015
Natural gas (Mcf/d)	**45,005**	41,794	**45,422**	47,589
Crude oil (bbls/d)	**140**	225	**177**	160
Natural gas liquids (bbls/d)	**209**	300	**237**	475
Condensate (bbls/d)	**760**	723	**841**	918
Total (boe/d)	**8,609**	8,213	**8,826**	9,485
Total production (boe)	**792,069**	755,634	**3,230,434**	3,461,850

Production for the three and twelve months ended December 31, 2016 averaged 8,609 boe/d and 8,826 boe/d compared to production of 8,213 boe/d and 9,485 boe/d, respectively in 2015.

Average production declined 7 percent in 2016 as the Company's reduced drilling program was insufficient to offset natural production declines. In 2016, the Company brought 1.5 net wells onstream compared to 6.7 net wells in 2015. The Company expects to complete 3 net wells in the first half of 2017 and forecasts average production in the first half of 2017 to increase to 9,000 – 9,500 boe/d.

Fourth quarter production increased by 5 percent from prior year. The fourth quarter of 2015 included significant production downtime as the entire Simonette field was shut in for 14 days to accommodate the construction of the company's plant upgrade.

PRODUCTION REVENUE

	Three months ended December 31,		Twelve months ended December 31,	
$(000's)	**2016**	2015	**2016**	2015
Sales of natural gas, oil and condensate	**17,428**	13,341	**52,269**	71,496
Royalties	**(467)**	507	**(1,543)**	(2,900)
Production revenue	**16,961**	13,848	**50,726**	68,596

Production revenue was $16,961 in the fourth quarter of 2016 compared to $13,848 in 2015. The increase in production revenue is attributable to a five percent increase in production, a two percent increase in realized sales prices offset by increased royalty expense in 2016. For the twelve months ended December 31, 2016, total production revenue decreased 26 percent to $50,726 from $68,596 in the comparable period of 2015. The decrease in revenue is attributable to the 22 percent decrease in realized sales prices and seven percent decrease in production.

TOTAL REVENUE AND PRICING

The following tables present total revenue which is a non-GAAP financial measure, with no standardized meaning under the Company's GAAP and therefore may not be comparable to similar measures presented by other issuers:

$(000's)	Natural gas	Crude oil and condensate	Natural gas liquids	**2016 Total**	2015 Total
	Three months ended December 31,				
Sales of natural gas, oil and condensate	12,194	4,741	493	**17,428**	13,341
Realized gain (loss) on commodity contracts	(90)	(85)	–	**(175)**	2,771
Total revenue[1]	12,104	4,656	493	**17,253**	16,112

[1] Refer to non-GAAP measurements.

$(000's)	Natural gas	Crude oil and condensate	Natural gas liquids	**2016 Total**	2015 Total
	Twelve months ended December 31,				
Sales of natural gas, oil and condensate	32,020	18,345	1,904	**52,269**	71,496
Realized gain on commodity contracts	5,697	1,108	–	**6,805**	9,395
Total revenue[1]	37,717	19,453	1,904	**59,074**	80,891

[1] Refer to non-GAAP measurements.

Total revenue was $17,253 in the fourth quarter of 2016 compared to $16,112 in 2015. The increase in revenue is attributable to a five percent increase in production and a two percent increase in realized sales prices. For the twelve months ended December 31, 2016, total revenue decreased 27 percent to $59,074 from $80,891 in the comparable period of 2015. The decrease in revenue is attributable to the 22 percent decrease in realized sales prices and seven percent decrease in production.

$(000's)	Three months ended December 31, 2016	2015	Twelve months ended December 31, 2016	2015
Average prices				
Natural gas ($/Mcf)	**2.95**	2.16	**1.93**	2.73
Realized natural gas hedges ($/Mcf)	**(0.03)**	0.73	**0.34**	0.54
Natural gas including hedges ($/Mcf)	**2.92**	2.89	**2.27**	3.27
Crude oil and condensate ($/bbl)	**57.30**	52.32	**49.20**	53.78
Realized crude oil hedges ($/bbl)	**(1.03)**	–	**2.97**	–
Crude oil and condensate including hedges ($/bbl)	**56.27**	52.32	**52.17**	53.78
Natural gas liquids ($/bbl)	**25.61**	16.45	**21.94**	17.04
Average sales price before hedges ($/boe)	**22.00**	17.65	**16.18**	20.65
Average sales price including hedges ($/boe)	**21.78**	21.32	**18.29**	23.37
Benchmark pricing				
AECO-C spot (CDN$/Mcf)	**3.11**	2.48	**2.18**	2.71
WTI crude oil (US$/bbl)	**49.16**	42.02	**43.34**	48.68
Edmonton par price (CDN$/bbl)	**60.76**	52.88	**52.95**	57.62
US$/CDN$ exchange rate	**0.75**	0.75	**0.76**	0.78

For the year ended December 31, 2016, natural gas prices averaged $2.27/mcf down $1.00/mcf from $3.27/mcf in 2015. Prices remained low throughout most of 2016 as an unseasonably warm North American winter in 2015/16 resulted in record high North American natural gas inventories. Prices increased during the second half of the year through a combination of lower North American natural gas drilling activity, increased natural gas usage for power generation and U.S. exports that resulted in an improvement of supply/demand fundamentals and alleviated the large gas storage surplus. For the fourth quarter of 2016 natural gas prices averaged $2.92/mcf consistent with $2.89/mcf in 2015.

The Company realized natural gas prices before hedging for the three and twelve months ended December 31, 2016 of $2.95/mcf and $1.93/mcf. The Company's average natural gas price realization in the fourth quarter of 2016 was a five percent discount to AECO compared to a discount of 13 percent in 2015. The Company is currently marketing most of its natural gas at Simonette with short term sales contracts at fixed differentials to AECO. For the fourth quarter and year ended December 31, 2016, the Company realized an average price discount to AECO of $0.35/GJ and $0.45/GJ, respectively, prior to adjustments for heat content.

For the first quarter of 2017, Cequence has contracts on Alliance and TCPL that average 40,366 GJ/d at a blended discount to AECO of $0.31/GJ. Beginning April 1, 2017 the contracted volume drops down to 20,000 GJ/d then to 10,000 GJ/d on November 1, 2016. The Company is pursuing additional firm service but there is no guarantee that it will be able to secure it. If the Company cannot secure firm service it will be relying on interruptible service on both the Alliance and TCPL pipeline systems. Interruptible transportation service is expected to be more volatile than firm service which may result in higher transportation charges or inconsistent production times until additional firm service is contracted. Beginning, April 1, 2018 the Company will have 35,000 GJ/d of firm service with TCPL from its Simonette property.

Crude oil and condensate prices remained low throughout 2015 and 2016 with average Edmonton par prices declining eight percent in 2016. Crude oil and condensate prices before hedges for the fourth quarter of 2016 and twelve months ended December 31, 2016 were $57.30/bbl and $49.20/bbl, respectively, up ten percent and down nine percent from the same time period in 2015.

Natural gas liquids prices for the three and twelve months ended December 31, 2016 were $25.61/bbl and $21.94/bbl, respectively, up 56 percent and 29 percent from the same time period in 2015.

COMMODITY PRICE MANAGEMENT

	Three months ended December 31,		Twelve months ended December 31,	
$(000's)	**2016**	2015	**2016**	2015
Realized gain (loss) on commodity contracts	**(175)**	2,771	**6,805**	9,395
Unrealized gain (loss) on commodity contracts	**(4,402)**	396	**(8,294)**	(4,541)
Total	**(4,577)**	3,167	**(1,489)**	4,854

Cequence has a commodity price risk management program which provides the Company flexibility to enter into derivative and physical commodity contracts to protect future cash flows for planned capital expenditures against an unpredictable commodity price environment. In both 2015 and 2016, declining current crude oil and natural gas prices resulted in realized gains on commodity contracts that resulted in an increase in average sales prices of 13 percent in both years.

The fair value of the commodity contracts outstanding at December 31, 2016 was a current liability of $4,491 and non-current liability of $159 (December 31, 2015 – current asset of $3,644). Cequence has the following natural gas and crude oil hedges as at the date of this MD&A:

Term	Product	Type	Average Volume (GJ/d)	Average Price ($/GJ)	Average Price ($/mcf)[1]	Basis
January 1, 2017 to March 31, 2017	Gas	Swap	20,000	$2.66	$2.85	AECO
April 1, 2017 to September 30, 2017	Gas	Swap	22,500	$2.78	$2.98	AECO
October 1, 2017 to December 31, 2017	Gas	Swap	19,185	$2.76	$2.96	AECO
January 1, 2018 to March 31, 2018	Gas	Swap	7,500	$3.02	$3.23	AECO

(1) The conversion from GJ to Mcf is based on estimated average natural gas heat content of 37.8 MJ/m^3

Term	Product	Type	Average Volume (bbl/d)	Average Price (CDN$/bbl)	Basis
January 1, 2017 to December 31, 2017	Oil	Swap	366	$69.26	WTI

OPERATING NETBACK

($/boe)	Three months ended December 31, 2016	2015	Twelve months ended December 31, 2016	2015
Total revenue[1]	**21.78**	21.32	**18.29**	23.37
Royalty expense	**(0.59)**	0.67	**(0.48)**	(0.84)
Transportation expense	**(1.45)**	(1.77)	**(1.24)**	(1.83)
Operating costs	**(7.81)**	(9.30)	**(8.49)**	(9.17)
Operating netback, $/boe	**11.93**	10.92	**8.08**	11.53
Operating netback, excluding realized hedges, $/boe	**12.15**	7.25	**5.97**	8.81

[1] Total revenue is presented gross of royalties and includes realized gain (loss) on commodity contracts.

See Non-GAAP measures for definition of operating netback.

Cequence's operating netback for the three months ended December 31, 2016 increased nine percent to $11.93 per boe from $10.92 per boe in 2015. Excluding realized hedges, fourth quarter operating netbacks increased by 68 percent. Fourth quarter operating netbacks increased from prior year due to higher commodity prices and lower operating expenses.

For the twelve months ended December 31, 2016, the operating netback decreased by 30 percent to $8.08/boe from $11.53/boe in the comparative period of 2015. Excluding realized hedges, operating netbacks decreased by 32 percent. The decrease in 2016 annual operating netbacks is mainly due to lower total revenue that was partially offset by the reduction in operating costs.

ROYALTY EXPENSE

$(000's)	Three months ended December 31, 2016	2015	Twelve months ended December 31, 2016	2015
Crown	**(219)**	(893)	**(218)**	324
Freehold / Overriding	**686**	386	**1,761**	2,576
Total royalties	**467**	(507)	**1,543**	2,900
Royalties as a percentage of revenue, before hedging	**3%**	0%	**3%**	4%
Per unit of production ($/boe)	**0.59**	(0.67)	**0.48**	0.84

Royalty expense for the twelve months ended December 31, 2016 was consistent with prior year at three percent of sales of natural gas, oil and condensate. The average crown royalty rate remains low due to depressed commodity prices in both 2015 and 2016. Crown royalties operate on a sliding scale and royalty rates decrease when commodity prices decrease. In addition, credits against crown royalties for gas cost allowance remain at a similar amount despite lower crown royalties effectively reducing crown royalties to zero.

Royalty expense in the fourth quarter of 2015 included an adjustment for royalty credits received for gas cost allowance, capital cost allowance and custom processing fees received from prior period's royalty calculations.

In 2016, the Alberta government announced a Modernized Royalty Framework ("MRF") that came into effect on January 1, 2017. The royalty structure for wells drilled prior to January 1, 2017 will not change for a 10 year period from the royalty program's implementation date. The MRF will utilize a revenue minus cost framework with different royalty rates pre and post payout based on commodity prices and with a reduction in royalty rates for mature wells. Ninety percent of the Company's production is in Alberta and will be subject to the MRF. The economics of drilling wells at its Simonette property within expected price ranges, are estimated to improve modestly under the MRF. Cequence will continue to monitor the impact of the MRF on its operations in Alberta.

OPERATING COSTS

	Three months ended December 31,		Twelve months ended December 31,	
$(000's)	**2016**	2015	**2016**	2015
Operating costs	**6,184**	7,030	**27,436**	31,746
Per unit of production ($/boe)	**7.81**	9.30	**8.49**	9.17

In 2016, the Company focused on reducing field operating costs which resulted in improvements to chemical usage, trucking costs, field rentals and water handling. Operating costs for the three and twelve months ended December 31, 2016 improved by 12 percent and 14 percent, respectively, compared to 2015.

The operating cost improvements were achieved despite an increase in midstream capital costs following the Company's midstream transaction in June 2015. For the year ended December 31, 2016, midstream capital costs were $1.15/boe, an increase of $0.83/boe compared to 2015.

TRANSPORTATION EXPENSE

	Three months ended December 31,		Twelve months ended December 31,	
$(000's)	**2016**	2015	**2016**	2015
Transportation	**1,151**	1,339	**4,018**	6,323
Per unit of production ($/boe)	**1.45**	1.77	**1.24**	1.83

Transportation expense for the three and twelve months ended December 31, 2016 was $1.45/boe and $1.24/boe, respectively, a decrease of 18 percent and 32 percent from the comparative period in 2015. Transportation expenses decreased in 2016 compared to the prior year as the Company's firm gas transportation commitment on Alliance terminated in the fourth quarter of 2015. In addition, the Company observed an increase in trucking expenses in the first six months of 2015 due to wet weather in the field.

GENERAL AND ADMINISTRATIVE EXPENSES

	Three months ended December 31,		Twelve months ended December 31,	
$(000's)	**2016**	2015	**2016**	2015
G&A expenses, prior to restructuring charges	**1,597**	2,203	**6,926**	8,823
Restructuring charges	**–**	–	**2,341**	–
G&A expenses	**1,597**	2,203	**9,267**	8,823
Administrative and capital recovery	**(164)**	(199)	**(316)**	(864)
Total G&A expenses	**1,433**	2,004	**8,951**	7,959
Per unit of production, excluding restructuring charges ($/boe)	**1.81**	2.65	**2.05**	2.30
Per unit of production ($/boe)	**1.81**	2.65	**2.77**	2.30

In 2016, the Company made several improvements to its G&A cost structure including a significant staff reduction and relocation of the Company's office after its lease expired. Prior to restructuring charges G&A expenses were $6,926 or 22 percent lower than 2015. Annual G&A expense, excluding administrative and capital recovery, totalled $9,267 and includes $2,341 of non-recurring restructuring charges related to severance obligations.

In the fourth quarter of 2016, total G&A expenses were $1,433 or $1.81/boe, representing a 29 percent decrease from the fourth quarter of 2015. Fourth quarter G&A expenses do not include any restructuring charges and are representative of the Company's improved cost structure. G&A expenses are forecast be approximately $6,000 in 2017.

FINANCE COSTS

	Three months ended December 31,		Twelve months ended December 31,	
	2016	2015	**2016**	2015
Interest and standby fees expense on credit facilities	**53**	155	**411**	966
Interest expense and standby fees on senior notes	**1,464**	1,466	**5,821**	5,820
Amortization of transaction costs	**107**	95	**400**	360
Accretion expense on senior notes	**81**	74	**308**	277
Accretion expense on provisions	**220**	217	**803**	853
Total finance costs	**1,925**	2,007	**7,743**	8,276
Per unit of production ($/boe)	**2.43**	2.66	**2.40**	2.39
Interest per unit of production ($/boe)	**1.92**	2.15	**1.93**	1.96

Finance costs for the three and twelve months ended December 31, 2016 were $1,925 and $7,743 compared to $2,007 and $8,276 in 2015. Cequence incurred lower interest expense on its credit facility which was undrawn for the majority of 2016 and lower standby fees due to the reduced size of the senior credit facility.

OTHER INCOME

	Three months ended December 31,		Twelve months ended December 31,	
$(000's)	**2016**	2015	**2016**	2015
Gain on sale of property and equipment	**(220)**	(258)	**(3,202)**	(5,537)
Interest income	**(75)**	(183)	**(115)**	(357)
Other	**(49)**	(69)	**(241)**	(234)
Total other income	**(344)**	(510)	**(3,558)**	(6,128)

Other income for the twelve months ended December 31, 2016, includes a gain in 2016 of $2,964 from the sale of certain infrastructure assets that were partially depreciated. During the twelve months ended December 31, 2015, the Company completed sales of certain oil and gas properties, including the disposition of a 50 percent interest of existing Simonette facilities and related infrastructure, for total cash consideration of $44,763, subject to final adjustments. The sales in 2015 resulted in a gain recognized in comprehensive loss of $5,537.

DEPLETION AND DEPRECIATION

$(000's)	Three months ended December 31, 2016	2015	Twelve months ended December 31, 2016	2015
Depletion and depreciation expense	**10,757**	7,556	**31,622**	39,191
Impairment loss	**–**	144,000	**–**	230,400
Total depletion, depreciation and impairment	**10,757**	151,556	**31,622**	269,591
Per unit of production ($/boe)	**13.58**	200.57	**9.79**	77.87
Per unit of production, excluding impairment ($/boe)	**13.58**	10.00	**9.79**	11.32

Depletion and depreciation expense for the three and twelve months ended December 31, 2016, was $10,757 ($13.58/boe) and $31,622 ($9.79/boe). Depletion and depreciation rates for the twelve months ended December 31, 2016 have decreased from prior year due to reduced book values from impairment charges in 2015. During the fourth quarter of 2016, the remaining productive life of certain non-core areas was reduced resulting in additional depletion in the quarter.

On December 31, 2015, Cequence recorded a $144,000 impairment charge related to its Deep Basin and Peace River Arch CGUs. The impairments were a result of a lower outlook for future crude oil and natural gas prices compared to September 30, 2015. Commodity prices further deteriorated in the fourth quarter, in particular natural gas prices used in the first three years of the Company's third party reservoir engineers price forecast decreased by 20 percent, 10 percent and 7 percent, respectively. The impact of lower forecasted benchmark commodity prices was only partially offset by an increase in proved plus probable reserves of 7 percent and the positive impact of lower future development capital.

On September 30, 2015, Cequence recorded impairment of $86,400 related to its Deep Basin, Peace River Arch and Northeast British Columbia CGUs. The impairments were a result of a lower outlook for crude oil and natural gas prices.

Estimates of impairment are sensitive to changes in any of the key judgments, such as a revision in reserves or resources, a change in forecast commodity prices, expected royalties, required future development expenditures or expected future production costs, which could decrease or increase the recoverable amounts of assets and result in additional impairment charges or recovery of impairment charges.

$(000's)	Three months ended December 31, 2016	2015	Twelve months ended December 31, 2016	2015
Northeast British Columbia	**–**	–	**–**	10,000
Peace River Arch	**–**	2,000	**–**	7,500
Deep Basin	**–**	142,000	**–**	212,900
Total	**–**	144,000	**–**	230,400

SHARE BASED PAYMENTS

Stock Options

The Company has 11,003 stock options outstanding with an average exercise price of $0.86. The options have a five year life and vest evenly over a three year period on the anniversary date of their grant. For the twelve months ended December 31, 2016, Cequence recorded $708 (2015 – $1,107) in share based payment expense related to stock options with a corresponding increase to contributed surplus.

Restricted Share Units

The Company issues RSUs as part of its long term incentive program. The program is designed to offer cash compensation based on the underlying value of the RSU unit. RSUs are granted to directors, officers and employees of the Company and vest annually in equal amounts over a three year period. For the twelve months ended December 31, 2016, Cequence recognized $374 (2015 – $100) in share based payment expense related to RSUs with a corresponding increase to share based payment liability.

	RSUs		Stock Options	
Number (000's)	**2016**	2015	**2016**	2015
Outstanding, beginning of year	**1,707**	814	**11,395**	18,252
Granted	**2,622**	1,235	**6,295**	1,085
Cancelled/Forfeited	**(677)**	(17)	**(3,900)**	(12)
Settled	**(642)**	(325)	**–**	–
Expired	**–**	–	**(2,787)**	(7,930)
Outstanding, end of year	**3,010**	1,707	**11,003**	11,395

CAPITAL EXPENDITURES

	Three months ended December 31,		Twelve months ended December 31,	
$(000's)	**2016**	2015	**2016**	2015
Land	**199**	254	**886**	1,267
Geological and geophysical and capitalized overhead	**551**	271	**1,141**	1,218
Drilling, completions and workovers	**9,111**	12,844	**14,192**	26,380
Equipment, facilities and tie-ins	**1,595**	1,803	**6,366**	33,336
Office furniture and equipment	**4**	3	**5**	60
Capital expenditures	**11,460**	15,175	**22,590**	62,261
Property acquisitions(1)	**23**	–	**(60)**	1,062
Property dispositions(1)	**(77)**	1,176	**(5,234)**	(44,763)
Total capital expenditures	**11,406**	16,351	**17,296**	18,560

(1) Represent the cash proceeds from the sale of assets and cash paid for the acquisition of assets, as applicable.

For the twelve months ended December 31, 2016, capital expenditures, excluding acquisitions and dispositions, decreased to $22,590 from $62,261 in 2015. The Company reduced its drilling activity for most of 2016 as commodity prices remained low.

In the first quarter of 2016, the Company completed the addition of a shallow cut refrigeration upgrade at the Company's Simonette natural gas plant (50% working interest). The gas plant is currently expected to have sufficient spare capacity for the company's growth plans without additional large facility expenditures. The gas plant was operational in the first quarter of 2016 and is expected to provide Cequence with greater long term flexibility and improved pricing for natural gas and liquids from its Simonette property. Capital expenditures during the year also include the drilling of a water injection well at Simonette.

In the fourth quarter, commodity prices began to improve and the Company commenced a drilling program that includes 2 gross (1 net) Dunvegan wells and 2 gross (2 net) Montney wells. All four wells were spud in the fourth quarter with the Duvengan wells completed and on production in the first quarter of 2017 and the Montney wells expected to be on production in the second quarter of 2017.

During the twelve months ended December 31, 2016, the Company completed sales of certain non-producing oil and gas properties for total cash consideration of $5,234 (2015 – $44,763), subject to final adjustments. The sales resulted in a gain recognized in comprehensive loss of $3,202 (2015 – $5,537 gain).

INCOME TAXES

As at December 31, 2016, the Company has tax pools and available losses of $613,777 (December 31, 2015 – $616,084). Due to the uncertainty of future realization, a deferred tax asset has not been recognized.

At December 31, 2016, Cequence has the following tax pools:

Classification	Amount $(000's)	Annual Deductibility
Canadian exploration expense	153,846	100%
Non-capital losses	299,491	100%
Undepreciated capital cost	53,070	Primarily 25%, declining balance
Canadian oil and gas property expense	10,191	10%, declining balance
Canadian development expense	69,079	30%, declining balance
Other	28,100	Various
	613,777	

The Company's non-capital losses expire in 2027 and thereafter. Based on the Company's expected cash flow and available tax pools, Cequence does not expect to be taxable for the next three years.

PROVISIONS – DECOMMISSIONING LIABILITIES

Decommissioning liabilities represent the estimated future cost of abandoning and reclaiming the company's oil and natural gas wells and related facilities. Total decommissioning liabilities at December 31, 2016 were $38,161 compared to $40,708 at December 31, 2015. Decommissioning obligations are adjusted periodically for revisions to the future liability costs and the estimated timing of costs to be incurred in future years. The Company estimates that it will incur $366 of decommissioning obligations in 2017. The following table summarizes the changes in decommissioning liabilities for the respective periods:

	December 31, 2016	December 31, 2015
Balance, beginning of year	**40,708**	37,263
Property dispositions	**(364)**	(3,283)
Accretion expense	**803**	853
Liabilities incurred	**286**	1,819
Abandonment costs incurred	**(1,852)**	(720)
Revisions in estimated cash flows	**(126)**	3,195
Revisions due to change in discount rates	**(1,294)**	1,581
Balance, end of year	**38,161**	40,708

The total estimated, undiscounted cash flows, inflated at 2 percent, required to settle the obligations are $66,240 (December 31, 2015 – $69,020). These cash flows have been discounted using a risk-free interest rate of 2.34 percent (December 31, 2015 – 2.16 percent) based on Government of Canada long-term benchmark bonds. The Company expects these obligations to be settled in approximately 1 to 50 years (December 31, 2015 – 1 to 50 years).

LIQUIDITY AND CAPITAL RESOURCES

The Company's capital comprises shareholders' equity, demand credit facilities, senior notes and working capital. Cequence manages the capital structure and makes adjustments in light of economic conditions and the risk characteristics of the underlying assets.

$(000's)	**As at December 31, 2016**	As at December 31, 2015
Cash	**17,778**	13,246
Demand credit facility	**–**	–
Senior notes – principal	**(60,000)**	(60,000)
Accounts payable and accrued liabilities	**(36,124)**	(41,688)
Share based payment liability	**(341)**	(169)
Provisions – current	**(366)**	(826)
Accounts receivable	**14,145**	22,321
Deposits and prepaid expenses	**877**	1,669
Net debt[(1)(2)]	**(64,031)**	(65,447)
Funds flow from operations[(1)] – trailing twelve months	**11,250**	25,578
Net debt to funds flow from operations trailing twelve months[(2)]	**5.7:1**	2.6:1

(1) Refer to non-GAAP measurements.

(2) Prior period amounts have been adjusted to conform to current period presentation.

Cequence's objective is to maintain a flexible capital structure in order to meet its financial obligations and to execute its business plan throughout the commodity cycle. The oil and gas business involves a number of factors, including the timing of capital expenditures and volatile commodity prices that may cause the Company's net debt to funds flow ratio to fluctuate on a quarterly basis. Historically, the Company has managed its debt levels and working capital through its hedging program, issuing common shares, adjusting capital expenditures, and executing asset dispositions. The Company typically carries a working capital deficiency as cash balances are used to repay short term borrowings. Based on current projections, the Company expects to be able to fund its working capital deficiency with funds flow from operations.

At December 31, 2016, the Company's net debt to funds flow of 5.7:1 is higher than the Company's long term target of 2:1 due to the prolonged period of low commodity prices through 2015 and 2016. To manage its leverage and limit borrowing on its senior credit facility, the Company significantly reduced capital expenditures in 2016. The Company did not conduct any drilling activity for the first three quarters and focused its efforts on reducing both operating and general and administrative costs.

AECO prices improved in the latter half of 2016 and the Company began to realize the benefits of its costs saving initiatives. To illustrate the impact of these changes, the Company analyzed its December 31, 2016 net debt compared to fourth quarter annualized funds flow which resulted in an improved net debt to funds flow ratio of 2.4:1.

On October 28, 2016, Cequence completed the sale of 34,500 common voting shares on a Canadian development expenses "flow-through" basis at $0.29 per share for gross proceeds of $10,005. Proceeds of the offering allowed the Company to commence a winter drilling program in the fourth quarter without incurring additional bank debt in 2016. Based on the Company's anticipated funds flow, the winter drilling program will be financed by the proceeds of the financing, funds flow from operations and bank debt.

Senior Credit Facility

At December 31, 2016, Cequence had a $20,000 (December 31, 2015 – $60,000) term credit facility available from a syndicate of Canadian chartered banks. The senior credit facility is secured by a first floating charge debenture, general assignment of book debts and Cequence's oil and natural gas properties and equipment. The senior credit facility has a term date of May 31, 2017 and may be extended beyond the initial term, if requested by the Company and accepted by the lenders. If the credit facility does not continue to revolve, amounts borrowed under the facility must be repaid on the term date. The senior credit facility is reviewed on a semi-annual basis with the lender holding the right to request an additional review.

As at December 31, 2016 and 2015, the senior credit facility is undrawn. The company has letters of credit outstanding of $3,307 (December 31, 2015 – $3,207). The senior credit facility has a covenant that requires Senior Debt to twelve month trailing net income (loss) plus finance costs, share based payment expense, income tax expense (recovery), unrealized loss (gain) on commodity contracts, loss (gain) on sale of property and equipment, depletion and depreciation less costs related to onerous contracts to be less than 3:0 to 1:0, respectively. Senior Debt is defined as the sum of Consolidated Debt less the period end balance of the senior notes. Consolidated Debt is defined as the sum of the Company's period end balance of the credit facility and senior notes. The Company was in compliance with the lender's covenant at December 31, 2016 with a ratio of 0.2 times (December 31, 2015 – 0 times). At December 31, 2016, there are no restrictions on the Company's ability to draw on its credit facility.

Senior Notes

In October 2013, Cequence closed an investment with CPPIB Credit Investments Inc., ("CII"), a wholly-owned subsidiary of Canada Pension Plan Investment Board ("CPPIB"), for an initial investment by CII of $60,000 in unsecured five year senior notes with a further $60,000 of notes available at a future date, subject to the approval of both CII and Cequence on terms to be confirmed at the time of issuance. In addition, Cequence granted CII 3.0 million warrants to purchase common shares. The senior notes diversify the Company's capital structure by providing longer term debt that is not reserve-based or subject to periodic redetermination. The initial investment of $60,000 of senior notes were issued at par and carry a 9% coupon rate per annum. A standby charge of 0.7% is applied to the further $60,000 of notes available at a future date.

The senior notes contain incurrence covenants that use a Debt to Cashflow test of 2.5 times to limit the incurrence of certain indebtedness and restricted payments without debtholder approval. The incurrence covenants do not contain provisions that make the notes callable. For this purpose, Debt is defined as the Company's period end balance of the credit facility and senior notes. Cashflow is equivalent to the Company's calculation of funds flow for the trailing twelve months. At December 31, 2016, the Company's Debt to Cashflow ratio was more than 2.5 times. If current commodity prices persist, the Company expects that its Debt to Cashflow ratio will remain in excess of 2.5 times in 2017.

The incurrence covenants limit the incurrence of additional debt, unless permitted by the debtholder, as follows:

- Senior secured debt is restricted to the maximum of $125,000; the current borrowing base; 30 percent of Adjusted Consolidated Net Tangible Assets ("ACTNA") and 75 percent of the NPV 10% of the Company's PDP reserves as determined by GLJ Petroleum;
- Capital lease obligations exceeding $6,250 or 1.25% of ACTNA;
- Non-recourse debt exceeding $10,000;
- Other indebtedness exceeding $12,500;
- Debt subordinated to the senior notes; and
- Certain liens in connection with indebtedness.

The Company's ACTNA is defined as the value of the Company's total proved reserves before taxes, plus the value of tangible assets less working capital. At December 31, 2016 ACTNA is $241,779. The Company does not currently expect the incurrence covenants in the senior note indenture to restrict its planned activities.

Generally, the incurrence covenants also restrict payments as follows:

- dividends and other distributions;
- stock repurchases;
- subordinated debt prepayment; and
- certain investments outside of the oil and gas business.

Certain restricted payments are excluded from the general restrictions or are permitted, including a general lifetime exclusion of $12,500. A full detail of the Trust Indenture dated October 3, 2013 is filed at sedar.com. The Company does not currently anticipate initiating a payment that would be restricted by the trust indenture.

Commitments

Cequence has assumed various commitments in the normal course of operations and financing activities.

	2017	2018	2019	2020	2021+	Total
Office leases	367	350	262	–	–	979
Pipeline transportation	588	1,915	2,350	2,350	12,328	19,531
Gas processing	4,154	4,154	4,154	4,166	38,780	55,408
Total	5,109	6,419	6,766	6,516	51,108	75,918

Cequence has a year take or pay agreement for gas processing with the operator of the Simonette facility. The minimum commitment under the take or pay of 42 mmcf/d or approximately $4,154 per year concluding April 30, 2030. In addition, The Company has firm transportation on a major pipeline system for 9 mmcf/d for the period January 1, 2016 to March 31, 2018 and 35 mmcf/d for the period April 1, 2018 to March 30, 2026.

Subsequent to December 31, 2016, the Company has entered into a binding contract to ship 10,850 GJ/d of natural gas on the TransCanada mainline system from the Empress receipt point to the Dawn hub in Ontario subject to regulatory approval with the National Energy Board and financial assurances. The term of the contract is 10 years and has early termination rights that can be exercised following the initial five years of service. The toll for this service is $0.77/GJ. The Company currently expects to begin shipping gas under these arrangements on April 1, 2018. The contract provides Cequence with pricing diversification for approximately 20 percent of its natural gas production.

OUTSTANDING SHARE DATA

Details of share capital and share awards outstanding are as follows:

	December 31, 2016	December 31, 2015
Common shares	**245,528**	211,028
Stock options	**11,003**	11,395
Restricted share units	**3,010**	1,707
Warrants	**3,000**	3,000

Cequence has an unlimited number of common voting shares and common non-voting shares with no par value.

Warrants have an exercise price of $2.03 to purchase common shares.

On October 28, 2016, the Company completed the sale, on a private placement basis, of 34,500 common voting shares on a Canadian development expenses “flow-through” basis at $0.29 per share for gross proceeds of $10,005. The financing allowed the Company to resume drilling operations in the fourth quarter.

As of the date of this MD&A, Cequence had the following securities outstanding: 245,528 common voting shares, 3,000 warrants to purchase common shares, 15,878 stock options and 3,711 RSUs.

SELECTED FINANCIAL INFORMATION

A reconciliation of cash flow from operating activities to funds flow from operations and other selected financial information is as follows:

	Three months ended December 31,		Twelve months ended December 31,		
$(000's)	**2016**	2015	**2016**	2015	2014
Cash flow from operating activities	**6,084**	3,266	**11,641**	31,884	68,132
Decommissioning liabilities expenditures	**259**	376	**1,852**	720	1,382
Net change in non-cash working capital	**282**	1,232	**(2,243)**	(7,026)	1,136
Funds flow from operations	**6,625**	4,874	**11,250**	25,578	70,650
Per share – basic ($)	**0.03**	0.02	**0.05**	0.12	0.33
Per share – diluted ($)	**0.03**	0.02	**0.05**	0.12	0.33
Total revenue	**17,253**	16,112	**59,074**	80,891	136,893
Comprehensive income (loss)	**(9,077)**	(146,585)	**(28,057)**	(250,072)	79,368
Per share – basic ($)	**(0.04)**	(0.69)	**(0.13)**	(1.19)	0.38
Per share – diluted ($)	**(0.04)**	(0.69)	**(0.13)**	(1.19)	0.37
Total assets	**388,858**	409,559	**388,858**	409,559	678,831
Demand credit facilities	**–**	–	**–**	–	–
Senior notes – principal	**60,000**	60,000	**60,000**	60,000	60,000

Funds flow from operations was $6,625 for the three months ended December 31, 2016 compared to $4,874 in 2015. The quarterly increase in funds flow is due to increased production volumes combined with lower operating, G&A and interest expenses. Annual funds flow from operations decreased by 56 percent from 2015. The decrease in annual funds flow is primarily a result of lower commodity prices and to a lesser extent lower production volumes.

Cequence recorded a comprehensive loss of $9,077 for the three months ended December 31, 2016 compared to a loss of $146,585 in 2015. The decrease is mainly due to the recording of $144,000 of impairment expense in the fourth quarter of 2015.

Cequence recorded a comprehensive loss of $28,057 for the twelve months ended December 31, 2016 compared to a loss of $250,072 in 2015. The decrease in comprehensive loss is mainly due to impairments recorded in 2015.

QUARTERLY INFORMATION

FINANCIAL

($(000's) except per share data)	**2016 Q4**	**2016 Q3**	**2016 Q2**	**2016 Q1**	2015 Q4	2015 Q3	2015 Q2	2015 Q1
Total revenue[1]	**17,253**	14,707	11,343	15,772	16,112	19,383	21,802	23,594
Royalties expense	**467**	636	(125)	565	(507)	368	1,016	2,023
Transportation expense	**1,151**	1,001	774	1,092	1,339	1,323	1,757	1,903
Operating costs	**6,184**	6,228	5,812	9,212	7,031	8,951	7,954	7,811
Comprehensive income (loss)	**(9,077)**	(880)	(12,212)	(5,888)	(146,585)	(99,070)	246	(4,662)
Per share – basic and diluted	**(0.04)**	(0.00)	(0.06)	(0.03)	(0.69)	(0.47)	0.00	(0.02)
Funds flow from (used in) operations[2]	**6,625**	3,385	1,554	(314)	4,874	5,139	7,283	8,283
Per share – basic	**0.03**	0.02	0.01	(0.00)	0.02	0.02	0.03	0.04
Per share – diluted	**0.03**	0.02	0.01	(0.00)	0.02	0.02	0.03	0.04
Capital expenditures, net	**11,460**	2,810	958	7,362	15,175	4,656	19,848	22,582
Net acquisitions (dispositions)[3]	**(54)**	(5,167)	138	(211)	1,176	1,136	(43,078)	(2,935)
Total capital expenditures	**11,406**	(2,357)	1,096	7,151	16,351	5,792	(23,230)	19,647

[1] Total revenue is presented gross of royalties and includes realized gains (loss) on commodity contracts.
[2] Funds flow from (used in) operations is calculated as cash flow from operating activities before adjustments for decommissioning liabilities expenditures and net changes in non-cash working capital.
[3] Represents the cash proceeds from the sale of assets and cash paid for the acquisition of assets, as applicable.

OPERATIONAL

	2016 Q4	**2016 Q3**	**2016 Q2**	**2016 Q1**	2015 Q4	2015 Q3	2015 Q2	2015 Q1
Production volumes								
Natural gas (Mcf/d)	**45,005**	44,320	40,127	52,253	41,794	43,987	48,665	56,105
Oil (bbls/d)	**140**	175	178	218	225	199	100	115
NGLs (bbls/d)	**209**	261	244	235	300	485	562	554
Condensate (bbls/d)	**760**	798	748	1,061	723	807	953	1,197
Total (boe/d)	**8,609**	8,621	7,857	10,223	8,213	8,822	9,726	11,217
Average selling price, including realized hedges								
Natural gas ($/Mcf)	**2.92**	2.28	1.73	2.10	2.89	3.46	3.35	3.33
Crude oil and condensate ($/bbl)	**56.27**	53.78	54.01	46.69	52.31	50.08	63.18	50.13
NGLs ($/bbl)	**25.61**	24.09	21.50	16.68	16.45	16.80	17.49	17.10
Total ($/boe)	**21.78**	18.54	15.86	16.95	21.32	23.88	24.63	23.37
Operating netback, including realized hedges ($/boe)								
Price	**21.78**	18.54	15.86	16.95	21.32	23.88	24.63	23.37
Royalties	**(0.59)**	(0.80)	0.17	(0.61)	0.67	(0.45)	(1.15)	(2.00)
Transportation	**(1.45)**	(1.26)	(1.08)	(1.17)	(1.77)	(1.63)	(1.99)	(1.88)
Operating costs	**(7.81)**	(7.85)	(8.13)	(9.90)	(9.30)	(11.03)	(8.99)	(7.74)
Operating netback	**11.93**	8.63	6.82	5.27	10.92	10.77	12.50	11.75

Funds flow from operations is impacted from quarter to quarter primarily due to changes in productions volumes, realized average selling prices, royalties, operating expenses, transportation costs and G&A expense. The Company's production volumes are approximately 85 percent natural gas and fluctuations in natural gas prices have the greatest impact on the Company's revenue and funds flow from operations.

The decline in production revenue and funds flow beginning in the first quarter 2015 can be attributed to declining commodity prices and lower production volumes. Canadian AECO natural gas prices averaged $2.18/mcf in 2016, a decrease of 20% from $2.71/mcf in 2015. Production volumes decreased in the both 2015 and 2016 as the Company reduced capital expenditures on new wells due to the extended period of low gas prices.

The Company's quarterly net comprehensive income (loss) is affected by fluctuations in non-cash charges, in particular, depletion, depreciation and impairment expense, accretion of decommissioning obligations, gains/losses on derivative financial instruments, share based payments and other expense (income). During 2015, the Company recorded impairment expense of $230,400, including $144,000 in the fourth quarter. Impairments recognized were mainly the result of declining benchmark natural gas prices. These impairments cause significant reductions and increased volatility in the Company's net comprehensive income (loss).

Please refer to the results of operations and other sections of this MD&A and the Company's previously issued MD&A for detailed discussions on variances between reporting periods and changes in prior periods.

OUTLOOK INFORMATION

On November 10, 2016, the Company updated its 2016 guidance and provided preliminary guidance for the first half of 2017:

(000's, except per share and per unit references)	**May 2016 Guidance 2016**	**Revised Guidance 2016**	**Actual 2016**	**Six Months Ended June 30, 2017**
Average production, BOE/d[1]	8,500	8,800	8,826	9,000-9,500
Funds flow from operations ($)[2][4]	2,000	8,000	11,250	11,000-12,000
Funds flow from operations per share[2]	0.01	0.04	0.05	0.05
Capital expenditures, prior to dispositions ($)	14,000	22,000	22,590	15,500
Capital expenditures, net of dispositions ($)	7,000	17,000	17,296	15,500
Operating and transportation costs ($/boe)	11.30	10.25	9.73	10.25
G&A costs ($)[4]	8,500	8,800	8,951	3,000
Royalties (% revenue)	6	4	4	8
Crude – WTI (US$/bbl)	43.00	43.50	43.34	50.00
Natural gas – AECO (CDN$/GJ)	1.90	2.00	2.18	2.75
Period end, net debt ($)[3]	70,000	64,000	64,031	67,000-69,000
Weighted average basic shares outstanding	211,000	216,900	217,060	245,500

(1) Average production estimates on a per BOE basis are comprised of 85% natural gas and 15% oil and natural gas liquids.

(2) Funds flow from operations is calculated as cash flow from operating activities before adjustments for decommissioning liabilities expenditures and net changes in non-cash working capital.

(3) Net debt is calculated as working capital (deficiency) less the aggregate principal amount of the senior notes.

(4) 2016 annual G&A costs include $2,341 in restructuring charges.

The Company revised its original guidance twice in 2016 to incorporate lower operating costs realized from its costs reduction efforts throughout the year, increased capital expenditures following the October financing and the impact of higher pricing and production volumes. As a result, the company's 2016 funds flow of $11,250 exceeded its revised guidance of $8,000.

The Company has provided guidance for the first half of 2017. Capital expenditures are expected to be $15,500 and include the completion of the Company's winter drilling program of two Montney wells and one net Dunvegan well at Simonette. The Company forecasts average production for the first half of 2017 to be between 9,000 – 9,500 boe/d. The Company does not expect to issue full year guidance until it has assessed the results of the company's winter drilling program which is not expected until Q2 2017.

DISCLOSURE CONTROLS AND INTERNAL CONTROLS OVER FINANCIAL REPORTING

The Chief Executive Officer ("CEO") and Executive Vice President, Finance and Chief Financial Officer ("CFO") are responsible for designing internal controls over financial reporting or causing them to be designed under their supervision in order to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with IFRS. The Company's CEO and CFO have designed, or caused to be designed under their supervision, disclosure controls and procedures to provide reasonable assurance that information required to be disclosed by the Company in its annual filings, interim filings or other reports filed or submitted by it under securities legislation is recorded, processed, summarized and reported within the time periods specified in the securities legislation and include controls and procedures designed to ensure that information required to be disclosed by an issuer in its annual filings, interim filings or other reports filed or submitted under securities legislation is accumulated and communicated to the Company's management, including its CEO and CFO, as appropriate to allow timely decisions regarding required disclosure.

The Committee of Sponsoring Organizations ("COSO") framework provides the basis for management's design of internal controls over financial reporting. Management and the Board work to mitigate the risk of a material misstatement in financial reporting; however, a control system, no matter how well conceived or operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met and it should not be expected that the disclosure and internal control procedures will prevent all errors or fraud.

As at December 31, 2016, CEO and CFO have concluded, based on their evaluation of the design and operating effectiveness of the Company's disclosure controls and procedures and internal controls over financial reporting ("ICFR") that disclosure controls and procedures and ICFR are effective.

FUTURE ACCOUNTING POLICIES

In April 2016, the IASB issued its final amendments to IFRS 15 "Revenue from Contracts with Customers", which replaces IAS 18 "Revenue", IAS 11 "Construction Contracts", and related interpretations. IFRS 15 provides a single, principles-based five-step model to be applied to all contracts with customers. The standard requires an entity to recognize revenue to reflect the transfer of goods and services for the amount it expects to receive, when control is transferred to the purchaser. Disclosure requirements have also been expanded. The standard is required to be adopted either retrospectively or using a modified retrospective approach for annual periods beginning on or after January 1, 2018, with earlier adoption permitted. IFRS 15 will be applied by Cequence on January 1, 2018. The Company is currently evaluating the impact of adoption of this standard and the effect on Cequence's consolidated financial statements has not yet been determined.

Since November 2009, the IASB has been in the process of completing a three phase project to replace IAS 39, "Financial Instruments: Recognition and Measurement" with IFRS 9 "Financial Instruments", which includes requirements for hedge accounting, accounting for financial assets and liabilities and impairment of financial instruments. As of February 2014, the mandatory effective date of IFRS 9 has been tentatively set to January 1, 2018. The Company is assessing the effect of this future pronouncement on its consolidated financial statements.

In January 2016, the IASB issued IFRS 16 "Leases". For lessees applying IFRS 16, a single recognition and measurements model for leases would apply, with required recognition of assets and liabilities for most leases. The standard will come into effect for annual periods beginning on or after January 1, 2019, with earlier adoption permitted if the entity is also applying IFRS 15 "Revenue from Contracts with Customers". The Company is currently evaluating the impact of adoption of this standard and the effect on Cequence's consolidated financial statements has not yet been determined.

APPLICATION OF CRITICAL ACCOUNTING ESTIMATES

The significant accounting policies used by Cequence are disclosed in note 2 to the consolidated financial statements. Certain accounting policies require that management make appropriate decisions with respect to the formulation of estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses. Management reviews its estimates on a regular basis. The emergence of new information and changed circumstances may result in actual results or changes to estimate amounts that differ materially from current estimates. The following discussion identifies the critical accounting policies and practices of the Company and helps to assess the likelihood of materially different results being reported.

RESERVES

Oil and gas reserves are estimates made using all available geological and reservoir data, as well as historical production data. All of the Company's reserves were evaluated and reported on by an independent qualified reserves evaluator. However, revisions can occur as a result of various factors including: actual reservoir performance, change in price and cost forecasts or a change in the Company's plans. Reserve changes will impact the financial results as reserves are used in the calculation of depletion and are used to assess whether asset impairment occurs.

DEPLETION

The net carrying value of development and production assets plus future development costs on proved plus probable reserves is depleted using the unit of production method based on proved and probable reserves, gross of royalties, as determined by independent engineers, on an area by area basis. An increase in estimated proved plus probable reserves would result in a reduction in depletion expense. A decrease in estimated future development costs would also result in a reduction in depletion expense.

DEVELOPMENT AND PRODUCTION COSTS

Items of property and equipment, which include oil and gas development and production assets, are measured at cost less accumulated depletion and depreciation and accumulated impairment losses.

Development and production assets are grouped into CGUs for impairment testing. CGUs are defined as the smallest identifiable group of assets that generates cash inflows that are largely independent of the cash inflows from other assets or groups of assets. The Company evaluates the geography, geology, production profile and infrastructure of its assets in determining its CGUs. Based on this assessment, Cequence's CGUs are generally composed of significant development areas. The Company reviews the composition of its CGUs at each reporting date to assess whether any changes are required in light of new facts and circumstances. When significant parts of an item of property and equipment, including oil and natural gas interests, have different useful lives, they are accounted for as separate items (major components).

IMPAIRMENT

The carrying amounts of all assets, other than financial assets and deferred tax assets, are reviewed at each reporting date to determine whether there is indication of an impairment loss. If any such indication exists, the asset's recoverable amount is estimated.

The recoverability of the carrying amount of an exploration and evaluation asset is dependent on successful development and commercial exploitation, or alternatively, sale of the respective area of interest. Where a potential impairment is indicated, an assessment is performed for each field or area to which the exploration and evaluation expenditure is attributed. To the extent that capitalized expenditures are not expected to be recovered, the excess of the carrying amount over the recoverable amount is recognized immediately.

The recoverable amount of a development and production asset (or CGU) or other intangible asset (or CGU) is determined as the higher of its value in use and fair value less cost to sell. Value in use is determined by estimating future cash flows after taking into account the risks specific to the asset (or group of assets within a CGU) and discounting them to their present value using a pre-tax discount rate that reflects the current market assessment of the time value of money. In determining fair value less cost to sell, an appropriate valuation model is used. These calculations are corroborated by external valuation metrics or other available fair value indicators wherever possible.

Where the carrying amount of a development and production asset (or CGU) or other intangibles asset exceeds its recoverable amount, the excess is recognized immediately in comprehensive income (loss).

Where an impairment loss subsequently reverses, the carrying amount of the asset (or CGU) is increased to the revised estimate of its recoverable amount, but only to the extent that the asset's carrying amount does not exceed the carrying amount that would have been determined, net of depreciation or depletion, if no impairment loss had been recognized.

DECOMMISSIONING LIABILITIES

The Company records a liability for the fair value of legal obligations associated with the retirement of petroleum and natural gas assets. The liability is equal to the discounted fair value of the obligation in the period in which the asset is recorded with an equal offset to the carrying amount of the asset. The liability then accretes to its fair value with the passage of time and the accretion is recognized as finance costs in the financial statements. The total amount of the decommissioning liability is an estimate based on the Company's net ownership interest in all wells and facilities, the estimated costs to abandon and reclaim the wells and facilities and the estimated timing of the costs to be incurred in future periods. The total amount of the estimated cash flows required to settle the decommissioning liabilities, the timing of those cash flows and the discount rate used to calculate the present value of those cash flows are all estimates subject to measurement uncertainty. Any change in these estimates would impact the decommissioning liabilities and the accretion expense.

SHARE BASED PAYMENTS

The Company utilizes stock options and RSUs for its long term compensation program for directors, officers, employees and other service providers. Compensation costs attributable to stock options granted are measured at fair value at the date of grant and are expensed over the vesting period, using a graded vesting schedule, with a corresponding increase in contributed surplus. When stock options are exercised, the cash proceeds together with the amount previously recorded as contributed surplus are recorded as share capital. The Company incorporates an estimated forfeiture rate for stock options that will not vest, and subsequently adjusts for actual forfeitures as they occur.

The RSUs are accounted for in accordance with the requirements for cash-settled share-based payment transactions with the value of one RSU being notionally equivalent to one Cequence common share. Cequence has the option to settle the RSUs with cash or with Cequence common shares, however, management's intent is to settle the RSUs in cash and the amount settled is expected to be deductible for income tax purposes. Compensation costs attributable to RSU granted are measured at fair value at the date of grant and subsequently remeasured each period end date and are expensed over the vesting period, using a graded vesting schedule, with a corresponding adjustment to share based payment liability. The Company incorporates an estimated forfeiture rate for RSUs that will not vest, and subsequently adjusts for actual forfeitures as they occur.

SENIOR NOTES

The Corporation uses estimates to allocate the proceeds from senior notes issuances between debt and the equity components, as appropriate.

INCOME TAXES

The determination of income and other tax assets and liabilities requires interpretation of complex laws and regulations. All tax filings are subject to audit and potential reassessment after the lapse of considerable time. Accordingly, the actual income tax asset may differ significantly from that estimated and recorded by management.

The recognition of a deferred income tax asset is also based on estimates of whether it is probable that the Company is able to realize these assets. This estimate, in turn, is based on estimates of proved and probable reserves, future oil and natural gas prices, royalty rates and costs. Changes in these estimates could materially impact comprehensive income (loss) and the deferred income tax asset recognized.

COMMODITY CONTRACTS

The fair value of commodity contracts and the resultant unrealized gains (loss) on commodity contracts is based on estimates of future natural gas and crude oil prices.

OTHER ESTIMATES

Management estimates of revenues, royalties and operating costs as at a specific reporting date but for which actual revenues and costs have not yet been received. In addition, estimates are made on capital projects which are in progress or recently completed where actual costs have not been received by the reporting date. The Company obtains the estimates from the individuals with the most knowledge of the activity and from all project documentation received. The estimates are reviewed for reasonableness and compared to past performance to assess the reliability of the estimates. Past estimates are compared to actual results in order to make informed decisions on future estimates.

FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

The Company's financial instruments, including derivative financial instruments, recognized in the consolidated balance sheet consist of cash, accounts receivable, commodity contracts, demand credit facilities, senior notes and accounts payable and accrued liabilities.

The Company's cash, accounts receivable, demand credit facilities and accounts payable and accrued liabilities approximate their carrying values due to their short terms to maturity and the floating interest rate on the Company's debt. The senior notes bear interest at rates available to Cequence and accordingly the fair value approximates the carrying value excluding deferred financing costs.

The Company is engaged in the exploration, development, production and acquisition of crude oil and natural gas. This business is inherently risky and there is no assurance that hydrocarbon reserves will be discovered and economically produced. Financial risks associated with the petroleum industry include fluctuations in commodity prices, interest rates and currency exchange rates along with the credit risk of the Company's industry partners. Operational risks include reservoir performance uncertainties, the reliance on operators of the Company's non-operated properties, competition, environmental and safety issues, and a complex and changing regulatory environment.

The primary risks and how the Company mitigates them are as follows:

Commodity price and exchange rate volatility

Revenues and consequently cash flows fluctuate with commodity prices and the U.S. / Canadian dollar exchange rate. Commodity prices are determined on both a regional and global basis and circumstances that occur locally in various parts of the world are outside of the control of the Company. The Company protects itself from fluctuations in prices by maintaining an appropriate hedging strategy and managing its balance sheet in light of prevailing economic conditions. Cequence enters into commodity price contracts to actively manage the risks associated with price volatility and thereby protect the Company's cash flows used to fund its capital program. Comprehensive loss for the year ended December 31, 2016 includes $6,805 of realized gain (2015 – $9,395 realized gain) and $8,294 of unrealized loss (2015 – $4,541 loss) on these transactions.

Cequence is also exposed to fluctuations in the exchange rate between the Canadian and U.S. dollar. Most commodity prices are based on U.S. dollar benchmarks that results in the Company's realized prices being influenced mainly by the U.S. / Canadian currency exchange rates. As at December 31, 2016, the Company has a no forward contracts, foreign exchange contracts or other significant items denominated in foreign currencies.

Interest rate risk

The Company is exposed to interest rate risk to the extent that changes in market interest rates impact its borrowings under the floating rate credit facilities. The floating rate debt is subject to interest rate cash flow risk, as the required cash flows to service the debt will fluctuate as a result of changes in market rates. The Company has no interest rate swaps or financial contracts in place as at or during the year ended December 31, 2016.

As at December 31, 2016, a 1 percent change in interest rates on the Company's outstanding debt, with all other variables constant, would result in a change in comprehensive loss of $nil ($nil after tax) (2015 – $nil ($nil after tax)).

Credit risk

Credit risk is the risk of financial loss to the Company if a counterparty to a financial instrument fails to meet its contractual obligations. The company is exposed to credit risk with respect to its cash, accounts receivable and commodity contract assets.

The Company's cash is held with a large established financial institution. The majority of the Company's accounts receivable are due from joint venture partners in the oil and gas industry and from marketers of the Company's petroleum and natural gas production. The Company mitigates its credit risk by entering into contracts with established counterparties that have strong credit ratings and reviewing its exposure to individual counterparties on a regular basis. At December 31, 2016, the Company has an allowance for doubtful accounts of $647 (2015 – $682).

Liquidity Risk

Liquidity risk is the risk that the Company will not be able to meet its financial obligations as they are due. The nature of the oil and gas industry is capital intensive and the Company maintains and monitors a certain level of cash flow to finance operating and capital expenditures. The Company believes it currently has sufficient credit facilities to satisfy its financial obligations as they come due.

The Company's ongoing liquidity is impacted by various external events and conditions, including commodity price fluctuations and the global economic environment.

The expected timing of cash flows relating to financial liabilities as at December 31, 2016 is as follows:

	< 1 Year	1 – 2 Years	2 – 5 Years	Thereafter
Senior notes – principal	–	60,000	–	–
Accounts payable and accrued liabilities	36,124	–	–	–
	36,124	60,000	–	–

Access to Capital Risk

The Company anticipates making substantial capital expenditures for the acquisition, exploration, development and production of oil and natural gas reserves in the future. As the Company's revenues have declined as a result of decreased commodity pricing, capital expenditures have been reduced. There can be no assurance that debt or equity financing, or cash generated by operations will be available or sufficient to meet these requirements or for other corporate purposes or, if debt or equity financing is available, that it will be on terms acceptable to the Company. The inability of the Company to access sufficient capital for its operations could have a material adverse effect on the Company's business, financial condition, results of operations and prospects.

Environmental Risk

The oil and natural gas industry is subject to environmental regulation pursuant to local, provincial and federal legislation. Such legislation may be changed to impose higher standards and potentially more costly obligations on Cequence. Furthermore, management believes the federal and provincial political parties appear to favor new programs for environmental laws and regulation, particularly in relation to the reduction of emissions, and there is no assurance that any such programs, laws or regulations, if proposed and enacted, will not contain emission reduction targets which Cequence cannot meet, and financial penalties or charges could be incurred as a result of the failure to meet such targets. In particular there is uncertainty regarding the Federal Government's future regulation of air emissions.

The provincial government of Alberta released its Climate Leadership Plan which will impact all consumers and businesses that contribute to carbon emissions in Alberta. This plan includes imposing carbon pricing that is applied across all sectors, starting at $20 per tonne on January 1, 2017 and moving to $30 per tonne on January 1, 2018, the phase-out of coal-fired power generation by 2030, a cap on oil sands emissions production of 100 megatonnes, and a 45 per cent reduction in methane emissions by the oil and gas sector by 2025. The Company expects the Climate Leadership Plan to increase energy costs and the cost of operating its properties located in Alberta.

Regulatory Risk

There can be no assurance that government royalties, income tax laws, environmental laws and regulatory requirements relating to the oil and gas industry will not be changed in a manner which adversely affects the Company or its shareholders. Although the Company has no control over these regulatory risks, it continuously monitors changes in these areas by participating in industry organizations and conferences, exchanging information with third party experts and employing qualified individuals to assess the impact of such changes on the Company's financial and operating results.

Exploration, Development and Production Risks

The long term commercial success of the Company depends on its ability to find, acquire, develop and commercially produce oil and natural gas reserves. Without the addition of new reserves, the Company's reserves will decline over time as existing reserves are exploited. A future increase in the Company's reserves will depend not only on its ability to explore and develop any properties but also on its ability to select and acquire suitable producing properties or prospects.

Future oil and natural gas exploration may involve unprofitable efforts, not only from dry wells, but from wells that are productive but do not produce sufficient net revenues to return a profit after drilling, operating and other costs. In addition, drilling hazards or environmental damage could greatly increase the cost of operations, and various field operating conditions may adversely affect the production from successful wells. These conditions include delays in obtaining governmental approvals or consents, shut-ins of connected wells resulting from extreme weather conditions, insufficient storage or transportation capacity or other geological or mechanical conditions.

Production delays and declines from normal field operating conditions cannot be eliminated and can be expected to adversely affect revenue and cash flow levels to varying degrees. To the extent the Company is not the operator of its oil and gas properties, the Company is dependent on such operators for the timing of activities related to such properties and will be largely unable to direct or control the activities of the operators.

Oil and natural gas exploration, development and production operations are subject to all the risks and hazards typically associated with such operations, including hazards such as fire, explosion, blowouts, cratering, sour gas releases and spills, each of which could result in substantial damage to oil and natural gas wells, pipelines, production facilities, other property and the environment or in personal injury. The Company employs prudent risk management practices and maintains suitable liability insurance but may become liable for damages arising from such events against which it cannot insure, elects not to insure or because of high premium costs or other reasons. Costs incurred to repair such damage or pay such liabilities will reduce the cash flow of the Company.

RISK ASSESSMENT

The acquisition, exploration and development of oil and natural gas properties and the production, transportation and marketing of oil and natural gas involves many risks, which may influence the ultimate success of the Company. While the management of Cequence realizes these risks cannot be eliminated, they are committed to monitoring and mitigating these risks. These risk include, but are not limited to:

- Volatility in market prices and demand for oil, NGLs and natural gas and hedging activities related thereto;
- Variance of the Company's actual capital costs, operating costs and economic returns from those anticipated;
- The ability to find, develop or acquire additional reserves and the availability of the capital or financing necessary to do so on satisfactory terms;
- Risks related to the exploration, development and production of oil and natural gas reserves and resources;
- Negative public perception of oil sands development, oil and natural gas development and transportation, hydraulic fracturing and fossil fuels;
- Actions by governmental authorities, including changes in government regulation, royalties, taxation, and wildlife management including the Caribou Action and Range Planning that may impact the Company's Simonette area;
- Actions by governmental authorities, including changes in government regulation, royalties and taxation;
- The availability, cost or shortage of service equipment, raw materials, supplies or qualified personnel;
- Dependence upon oil and gas infrastructure, certain of which the Company does not control;
- The ability to satisfy obligations under the Company's firm commitment transportation and gas processing arrangements;
- The possibility that the Company's drilling activities may encounter sour gas;
- The concentration of the Company's assets in the Simonette area;
- First Nations claims;
- Limited intellectual property protection for operating practices and dependence on employees and contractors;
- Environmental, health and safety requirements;
- Extensive competition in the Company's industry;
- Third party credit risk including dependence on limited customers and counterparties;
- Variations in foreign exchange rates and interest rates;
- Litigation.

For additional information regarding the risks that the Company is exposed to, see the disclosure provided under the heading "Risk Factors" in the AIF, which is available on the SEDAR website at www.sedar.com

FORWARD-LOOKING STATEMENTS

Certain statements contained within this MD&A constitute forward-looking statements. These statements relate to future events or the Company's future performance. All statements other than statements of historical fact may be forward-looking statements. Forward-looking statements are often, but not always, identified by the use of words such as "seek", "anticipate", "budget", "plan", "continue", "estimate", "expect", "forecast", "may", "will", "project", "predict", "potential", "targeting", "intend", "could", "might", "should", "believe", and similar expressions. Forward-looking statements in this MD&A include, but are not limited to, statements with respect to: projections with respect to natural gas production; the projection of future royalty, operating, transportation and G&A expenses; the projected impact of land access and regulatory issues; projections relating to the volatility of crude oil and natural gas prices in 2017 and beyond ; the Company's projected capital investment levels for 2017 and the source of funding therefore; the effect of the Company's risk management program, including the impact of derivative financial instruments; the impact of the climate change initiatives on operating costs; the impact of Western Canada pipeline constraints. Readers are cautioned not to place undue reliance on forward-looking statements, as there can be no assurance that the plans, intentions or expectations upon which they are based will occur.

By their nature, forward-looking statements involve numerous assumptions, known and unknown risks and uncertainties, both general and specific, that contribute to the possibility that the predictions, forecasts, projections and other forward-looking statements will not occur, which may cause the Company's actual performance and financial results in future periods to differ materially from any estimates or projections of future performance or results expressed or implied by such forward-looking statements. These assumptions, risks and uncertainties include, among other things: volatility of and assumptions regarding oil and natural gas prices; assumptions based upon Cequence's current guidance; fluctuations in currency and interest rates; product supply and demand; market competition; risks inherent in the Company's marketing operations, including credit risks; imprecision of reserves estimates and estimates of recoverable quantities of oil, natural gas and liquids from resource plays and other sources not currently classified as proved; the Company's ability to replace and expand oil and gas reserves; the Company's ability to generate sufficient cash flow from operations to meet its current and future obligations; the Company's ability to access external sources of debt and equity capital; the timing and cost of well and pipeline constructions; the Company's ability to secure adequate product transportation; changes in royalty, tax, environmental and other laws or regulations or the interpretations of such laws or regulations; risks associated with existing and potential future lawsuits and regulatory actions made against the Company; and other risks and uncertainties described from time to time in the reports and filings made with securities regulatory authorities by Cequence. 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 resources and reserves described can be profitably produced in the future.

The forward looking statements contained herein concerning production, sales prices, operating expenses and capital spending are based on Cequence's 2017 capital program. The material assumptions supporting the 2017 capital program are provided in the table above under the heading "Outlook Information".

Financial outlook information contained in this MD&A 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. The purpose of such financial outlook is to enrich this MD&A. Readers are cautioned that such financial outlook information contained in this MD&A should not be used for purposes other than for which it is disclosed herein.

Although Cequence believes that the expectations represented by such forward-looking statements are reasonable, there can be no assurance that such expectations will prove to be correct. Readers are cautioned that the foregoing list of important factors is not exhaustive. Furthermore, the forward-looking statements contained in this MD&A are made as of the date of this MD&A and, except as required by law, Cequence does not undertake any obligation to update publicly or to revise any of the included forward-looking statements, whether as a result of new information, future events or otherwise. The forward-looking statements contained in this MD&A are expressly qualified by this cautionary statement.