MANAGEMENT'S DISCUSSION AND ANALYSIS

Management's discussion and analysis ("MD&A") of financial conditions and results of operations should be read in conjunction with NuVista Energy Ltd.'s ("NuVista" or the "Company") interim financial statements for the three and six months ended June 30, 2018 and audited financial statements for the year ended December 31, 2017. The following MD&A of financial condition and results of operations was prepared at and is dated August 7, 2018. Our December 31, 2017 audited financial statements, Annual Information Form and other disclosure documents are available through our filings on SEDAR at **www.sedar.com** or can be obtained from our website at **www.nuvistaenergy.com**.

Basis of presentation

Unless otherwise noted, the financial data presented below has been prepared in accordance with Canadian generally accepted accounting principles ("GAAP") also known as International Financial Reporting Standards ("IFRS"). The reporting and measurement currency is the Canadian dollar. Natural gas is converted to a barrel of oil equivalent ("Boe") using six thousand cubic feet of gas to one barrel of oil. In certain circumstances natural gas liquid volumes have been converted to a thousand cubic feet equivalent ("Mcfe") on the basis of one barrel of natural gas liquids to six thousand cubic feet of gas. Boes and Mcfes may be misleading, particularly if used in isolation. A conversion ratio of one barrel to six thousand cubic feet of natural gas is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. Given that the value ratio based on the current price of crude oil as compared to natural gas is significantly different from the energy equivalency of 6:1, utilizing a conversion ratio on a 6:1 basis may be misleading as an indication of value. National Instrument 51-101 - "Standards of Disclosure for Oil and Gas Activities" includes condensate within the product type of natural gas liquids. NuVista has disclosed condensate values separate from natural gas liquids herein as NuVista believes it provides a more accurate description of NuVista's operations and results therefrom.

Advisory regarding forward-looking information and statements

This MD&A contains forward-looking statements and forward-looking information (collectively, "forward-looking statements") within the meaning of applicable securities laws. The use of any of the words "will", "expects", "believe", "plans", "potential" and similar expressions are intended to identify forward-looking statements. More particularly and without limitation, this MD&A contains forward looking statements, including management's assessment of: NuVista's future focus, strategy, plans, opportunities and operations; financial and commodity risk management strategy; NuVista's planned capital expenditures and sources of funding; NuVista's 60,000 Boe/d growth plan; the anticipated potential and growth opportunities associated with NuVista's asset base; NuVista's future exposure to AECO; 2018 capital spending, production and adjusted funds flow; the timing of NuVista's next borrowing base review; asset retirement obligations and the amount and timing of such expenditures and the source of funding thereof; the scope, timing and costs of environmental remediation required in connection with the pipeline spill in Northwest Alberta; deferred taxes and NuVista's tax pools; targeted net debt to annualized current quarter adjusted funds flow; environmental compliance costs and the effect of proposed changes to environmental regulation; industry conditions and anticipated accounting changes and their impact on NuVista's operations and financial position. By their nature, forward-looking statements are based upon certain assumptions and are subject to numerous risks and uncertainties, some of which are beyond NuVista's control, including the impact of general economic conditions, industry conditions, current and future commodity prices, currency and interest rates, anticipated production rates, borrowing, operating and other costs and adjusted funds flow, the timing, allocation and amount of capital expenditures and the results therefrom, anticipated reserves and the imprecision of reserve estimates, the performance of existing wells, the success obtained in drilling new wells, the sufficiency of budgeted capital expenditures in carrying out planned activities, access to infrastructure and markets, competition from other industry participants, availability of qualified personnel or services and drilling and related equipment, stock market volatility, effects of regulation by governmental agencies including changes in environmental regulations, tax laws and royalties; the ability to access sufficient capital from internal sources and bank and equity markets; and including, without limitation, those risks considered under "Risk Factors" in our Annual Information Form. Readers are cautioned that the assumptions used in the preparation of such information, although considered *reasonable at the time of preparation, may prove to be imprecise and, as such, undue reliance should not be placed on forward-looking statements. NuVista's actual results, performance or achievement could differ materially from those expressed in, or implied by, these forward-looking statements, or if any of them do so, what benefits NuVista will derive therefrom. NuVista has included the forward-looking statements in this MD&A in order to provide readers with a more complete perspective on NuVista's future operations and such information may not be appropriate for other purposes. NuVista disclaims any intention or obligation to update or revise any forward-looking statements, whether as a result of new information, future events or otherwise, except as required by law.*

This MD&A also contains future-oriented financial information and financial outlook information (collectively, "FOFI") about NuVista's prospective results of operations and adjusted funds flow, all of which are subject to the same assumptions, risk factors, limitations, and qualifications as set forth above. Readers are cautioned that the assumptions used in the preparation of such information, although considered reasonable at the time of preparation, may prove to be imprecise and, as such, undue reliance should not be placed on FOFI and forward-looking statements. NuVista's actual results, performance or achievement could differ materially from those expressed in, or implied by, these forward-looking statements and FOFI, or if any of them do so, what benefits NuVista will derive therefrom. NuVista has included the forward-looking statements and FOFI in order to provide readers with a more complete perspective on NuVista's future operations and such information may not be appropriate for other purposes. NuVista disclaims any intention or obligation to update or revise any forward-looking statements, whether as a result of new information, future events or otherwise, except as required by law.

Non-GAAP measurements

Within the MD&A, references are made to terms commonly used in the oil and natural gas industry. Management uses "adjusted funds flow", "adjusted funds flow per share", "annualized current quarter adjusted funds flow", "adjusted funds flow netback", "net debt", "total net debt", "net debt to annualized current quarter adjusted funds flow", "operating netback" ,"total revenue" and "adjusted working capital deficit" to analyze operating performance and leverage. These terms do not have any standardized meaning prescribed by GAAP and therefore may not be comparable with the calculation of similar measures for other entities. These terms are used by management to analyze operating performance on a comparable basis with prior periods and to analyze the liquidity of NuVista.

Adjusted funds flow is based on cash provided by operating activities as per the statement of cash flows before changes in non-cash working capital, asset retirement expenditures, and environmental remediation recovery. Adjusted funds flow as presented is not intended to represent operating cash flow or operating profits for the period nor should it be viewed as an alternative to cash flow from operating activities, per the statement of cash flows, net earnings (loss) or other measures of financial performance calculated in accordance with GAAP.

Adjusted funds flow per share is calculated based on the weighted average number of common shares outstanding consistent with the calculation of net loss per share. Total revenue equals oil and natural gas revenues including realized financial derivative gains/losses. Operating netback equals the total of revenues including realized financial derivative gains/losses less royalties, transportation and operating expenses calculated on a Boe basis. Adjusted funds flow netback is operating netback less general and administrative, deferred share units, and interest expense calculated on a Boe basis. Net debt is calculated as long-term debt plus senior unsecured notes plus adjusted working capital deficit. Adjusted working capital deficit is current assets less current liabilities and excludes the current portions of the financial derivative assets or liabilities, asset retirement obligations and deferred premium on flow through shares. Net debt to annualized current quarter adjusted funds flow is net debt divided by annualized current quarter adjusted funds flow.

Description of business

NuVista is an exploration and production company actively engaged in the development, delineation and production of condensate, oil and natural gas reserves in the Western Canadian Sedimentary Basin. NuVista's focus is on the scalable and repeatable condensate-rich Montney formation in the Alberta Deep Basin ("Wapiti Montney"). The common shares of NuVista trade on the Toronto Stock Exchange ("TSX") under the symbol NVA.

Drilling activity

	Three months ended June 30		Six months ended June 30	
Number of wells	**2018**	2017	**2018**	2017
Wells drilled - gross [1]	**8.0**	11.0	**16.0**	23.0
Wells drilled - net [1]	**7.9**	11.0	**15.9**	23.0
Wells completed - gross & net [2]	**1.0**	5.0	**9.0**	13.0
Wells brought on production - gross & net [3]	**6.0**	2.0	**10.0**	10.0

(1) Based on rig release date.
(2) Based on frac end date.
(3) Based on first production date of in-line test or on production and tied-in to permanent facilities.

For the three months ended June 30, 2018, NuVista drilled 8 (7.9 net) natural gas wells compared to 11 (11.0 net) natural gas wells in the comparable period of 2017. For the six months ended June 30 2018, NuVista drilled 15 (14.9 net) natural gas wells and 1 disposal well, compared to 23 (23.0 net) natural gas wells in the comparable period of 2017.

All wells in 2018 and 2017 were drilled in NuVista's Wapiti Montney operating area with a 100% success rate and an average working interest of 99.4% and 100% respectively.

Production

	Three months ended June 30			Six months ended June 30		
	2018	2017	% Change	**2018**	2017	% Change
Natural gas (Mcf/d)	**128,300**	91,623	40	**130,497**	95,647	36
Condensate (Bbls/d)	**11,758**	8,682	35	**11,537**	8,519	35
Natural gas liquids ("NGLs") (Bbls/d)	**2,893**	1,501	93	**2,781**	1,629	71
Total (Boe/d)	**36,035**	25,454	42	**36,067**	26,089	38
Condensate & NGLs weighting [1] & [2]	**41%**	40%		**40%**	39%	
Condensate weighting [2]	**33%**	34%		**32%**	33%	

(1) NGLs include butane, propane and ethane.
(2) Product weighting is based on total production.

Production for the three and six months ended June 30, 2018 increased 42% and 38% respectively over the comparative periods of 2017 as a result of production increases from new development in the Montney. Production remained consistent with first quarter 2018 production of 36,099 Boe/d. Condensate volume weighting remained consistent compared to the prior year comparative period, and increased from 31% in the first quarter of 2018.

Pricing

	Three months ended June 30			Six months ended June 30		
	2018	2017	% change	**2018**	2017	% change
Realized selling prices (1) & (2)						
Natural gas ($/Mcf)	**3.37**	3.72	(9)	**3.43**	3.74	(8)
Condensate ($/Bbl)	**81.99**	57.26	43	**77.94**	60.29	29
NGLs ($/Bbl)	**38.19**	23.53	62	**35.87**	21.00	71
Barrel of oil equivalent ($/Boe)	**41.82**	34.28	22	**40.12**	34.65	16
Benchmark pricing						
Natural gas - AECO 5A daily index (Cdn$/Mcf)	**1.18**	2.78	(58)	**1.63**	2.74	(41)
Natural gas - AECO 7A monthly index (Cdn$/Mcf)	**1.03**	2.77	(63)	**1.44**	2.86	(50)
Natural gas - NYMEX (monthly) (US$/MMbtu)	**2.80**	3.18	(12)	**2.90**	3.25	(11)
Natural gas - Chicago Citygate (monthly) (US$/MMbtu)	**2.58**	3.01	(14)	**2.93**	3.20	(8)
Natural gas - Dawn (daily) (US$/MMbtu)	**2.79**	3.11	(10)	**2.91**	3.16	(8)
Oil - WTI (US$/Bbl)	**67.88**	48.29	41	**65.37**	50.10	30
Oil - Edmonton Par - (Cdn$/Bbl)	**80.64**	61.87	30	**76.37**	62.91	21
Exchange rate - (Cdn$/US$)	**1.29**	1.35	(4)	**1.28**	1.33	(4)

(1) Prices exclude price risk management realized and unrealized gains and losses on financial derivative commodity contracts but includes gains and losses on physical sale contracts and natural gas price diversification.

(2) The average condensate and NGLs selling price is net of pipeline tariffs and fractionation fees.

Global oil prices continued their upward trend with the WTI benchmark increasing close to 8% from $62.87 in the first quarter of 2018 to average US$67.88/Bbl in the second quarter of 2018. US production growth continued its upward trajectory, however strong global demand coupled with OPEC led production cuts more than offset this growth. This led to storage withdrawals in the first half of this year with oil and refined product inventories now normalizing close to historic averages. Canadian heavy oil differentials widened significantly in the second quarter, nevertheless condensate prices maintained their strength with the Edmonton marker trading well above light oil prices averaging C$88.84/Bbl for the quarter.

There has been sizable growth in US gas production since last fall primarily from the Marcellus play along with associated gas from liquids production. This production growth was offset by growth in US LNG exports, exports to Mexico and cold winter weather that continued into the spring. While this led to a sizable storage deficit NYMEX gas prices compared to the first quarter of 2018 were only down 7% in the second quarter averaging US$2.80/ MMbtu. Eastern North American prices were slightly lower than NYMEX gas prices in the second quarter with spring being the typical shoulder season in the Chicago and Dawn markets. Gas production growth in Western Canada along with the start of the Nova maintenance season led to a significant reduction in local gas prices. AECO gas prices averaged $1.03/Mcf in the second quarter of 2018 representing a decrease of 45% from $1.86/Mcf in the first quarter of 2018 and a 63% decrease from the second quarter of 2017.

Revenue

Petroleum and natural gas revenue

	Three months ended June 30				Six months ended June 30			
	2018		2017		**2018**		2017	
($ thousands, except % amounts)	**$**	**% of total**	$	% of total	**$**	**% of total**	$	% of total
Natural gas [1]	**39,346**	**29**	30,945	39	**81,082**	**31%**	64,489	39%
Condensate	**87,729**	**64**	45,242	57	**162,754**	**62%**	92,955	57%
NGLs [2]	**10,056**	**7**	3,214	4	**18,051**	**7%**	6,193	4%
Total petroleum and natural gas revenue	**137,131**		79,401		**261,887**		163,637	

(1) Natural gas revenue includes price risk management gains and losses on physical delivery sale contracts. For the three months ended June 30, 2018, our physical delivery sales contracts totaled a $7.3 million gain (2017 – $3.0 million gain).
(2) Includes butane, propane, and ethane and an immaterial amount of sulphur revenue.

For the three months ended June 30, 2018, petroleum and natural gas revenue increased 73% over the comparable period of 2017, due primarily to a 42% increase in production and a 22% increase in realized prices for the quarter.

For the six months ended June 30, 2018, petroleum and natural gas revenue increased 60% over the comparable period of 2017, due primarily to a 38% increase in production and a 16% increase in realized selling prices.

Condensate volumes of 33% of total production in the second quarter of 2018, amounted to 64% of total petroleum and natural gas revenue.

Natural gas revenue

A breakdown of natural gas revenue is as follows:

	Three months ended June 30				Six months ended June 30			
	2018		2017		**2018**		2017	
($ thousands, except per unit amounts)	**$**	**$/Mcf**	$	$/Mcf	**$**	$/Mcf	$	$/Mcf
Natural gas revenue - AECO reference price [1]	**12,268**	**1.03**	23,236	2.77	**34,362**	1.44	49,189	2.86
Heat/value adjustment [2]	**1,201**	**0.10**	2,336	0.28	**3,184**	0.13	4,630	0.27
Transportation revenue [3]	**6,963**	**0.58**	1,541	0.18	**12,068**	0.51	3,043	0.18
Natural gas market diversification revenue	**11,659**	**1.04**	821	0.13	**20,062**	0.87	2,270	0.12
AECO physical delivery sales contract gains [4]	**7,255**	**0.62**	3,011	0.36	**11,406**	0.48	5,357	0.31
Total natural gas revenue	**39,346**	**3.37**	30,945	3.72	**81,082**	3.43	64,489	3.74

(1) Quarter average AECO 7A monthly index.
(2) Based on NuVista's historical adjustment of 9-10%.
(3) Cost of gas transportation from the transfer of custody sales point to the final sales point.
(4) Excludes price risk management realized and unrealized gains and losses on financial derivative commodity contracts but includes gains and losses on physical sale contracts.

For the three months ended June 30, 2018, natural gas revenue increased 27% over the comparable period of 2017, due to a 40% increase in production more than offsetting a 9% decrease in realized selling prices.

For the six months ended June 30, 2018, natural gas revenue increased 26% over the comparable period of 2017, due primarily to a 36% increase in production more than offsetting a 8% decrease in realized selling prices.

The Company's second quarter physical natural gas sales portfolio was approximately based on the following physical fixed price contracts or physical market deliveries:

	Three months ended June 30	
	2018	2017
AECO physical fixed price contracts	**22%**	68%
Dawn physical deliveries	**33%**	—%
Malin physical deliveries	**25%**	—%
Chicago physical deliveries	**20%**	32%

NuVista receives a premium to the AECO spot gas price due to the higher heat content of its natural gas production, as well as the various gas marketing arrangements that the Company has in place to diversify and gain exposure to alternative natural gas markets in North America outside Alberta to limit its exposure to AECO pricing. For the three months ended June 30, 2018, natural gas sales under AECO physical fixed price delivery sales contracts represented approximately 22% of the Company's total natural gas production. NuVista delivered approximately 33% of its natural gas production to Dawn, 25% to Malin, and 20% to Chicago.

NuVista's exposure to AECO floating prices is limited to approximately 1% of forecast volumes in 2018 as a result of this market egress, and the inclusion of pre-existing physical and financial delivery sales contracts at prices that are higher than current market prices as disclosed in section (b) under "*Commodity price risk management".* NuVista's existing contracts for firm transportation on export pipelines coupled with the financial AECO NYMEX basis natural gas sales price derivative contracts will result in long term price diversification and exposure to AECO floating pricing limited to approximately 15%-25% of volumes in 2019 and beyond.

Excluding the impact of realized gains on physical sales contracts, the average selling price for natural gas for the three and six months ended June 30, 2018 was $2.75/Mcf and $2.95/Mcf respectively, compared to $3.35/Mcf and $3.43/Mcf for the comparative periods of 2017, and $3.15/Mcf in the first quarter of 2018.

Condensate revenue

For the three months ended June 30, 2018, condensate revenue increased 94% over the comparable period of 2017 due to a 35% increase in production and a 43% increase in realized selling prices, which is consistent with a 41% increase in the WTI benchmark for the period.

For the six months ended June 30, 2018, condensate revenue increased 75% over the comparable period of 2017, due primarily to a 35% increase in production and a 29% increase in realized selling prices, which is consistent with a 30% increase in the WTI benchmark for the period.

Strong demand for condensate in Alberta results in benchmark condensate prices at Edmonton trading at a premium to Canadian light oil prices. NuVista’s realized condensate prices include adjustments for pipeline tariffs to Edmonton and quality differentials. Condensate realized selling prices averaged $81.99/Bbl and $77.94/Bbl in the three and six months ended June 30, 2018, an increase of 43% and 29% from $57.26/Bbl and $60.29/Bbl for the comparable periods of 2017, consistent with the increase in WTI prices compared to 2017.

NGL revenue

For the three months ended June 30, 2018, NGL revenue increased 213% over the comparable period of 2017, due to a 93% increase in production and a 62% increase in realized selling prices.

For the six months ended June 30, 2018, NGL revenue increased 191% over the comparable period of 2017, due primarily to a 71% increase in production and a 71% increase in realized selling prices.

Commodity price risk management

NuVista has a disciplined commodity price risk management program as part of its financial risk management strategy. The purpose of this program is to reduce volatility in financial results and help stabilize adjusted funds flow against the unpredictable commodity price environment. NuVista's Board of Directors has authorized the use of fixed price, put option and costless collar contracts ("Fixed Price Contracts"), and had approved the terms of NuVista's commodity price risk management program to allow the securing of minimum prices of the following:

(% of net forecast after royalty production)	First 18 month forward period	Following 18 month forward period	Following 24 month forward period
Natural Gas Fixed Price Contracts	up to 70%	up to 60%	up to 50%
Crude Oil Fixed Price Contracts	up to 70%	up to 60%	up to 30%

The Board of Directors has set limits for entering into natural gas basis differential contracts that are now the lesser of 50% of forecast natural gas production, net of royalties, or the volumes that would bring the combined natural gas basis differential contracts and natural gas fixed price contracts to 100% of forecast natural gas production, net of royalties. In addition, a maximum volume of up to 100,000 MMbtu/day has been approved, with a term of 6 to 7 years from the date any such swap is entered into.

Hedges on crude oil, natural gas liquids, natural gas, differentials and basis may be made in Canadian or U.S. dollars at the time the position is established and the position may be hedged to Canadian or U.S. dollars, as the case may be, during the term of the applicable hedge. Foreign currency of interest payments and of long-term debt, if there is that exposure, may also be hedged back to the Canadian dollar.

	Three months ended June 30					
($ thousands)	**2018**			2017		
	Realized gain (loss)	**Unrealized gain (loss)**	**Total gain (loss)**	Realized gain (loss)	Unrealized gain (loss)	Total gain (loss)
Natural gas	**2,881**	**(1,405)**	**1,476**	722	(3,916)	(3,194)
Condensate and NGLs	**(11,867)**	**(20,399)**	**(32,266)**	468	16,505	16,973
Foreign exchange	**75**	**(412)**	**(337)**	—	—	—
Gain (loss) on financial derivatives	**(8,911)**	**(22,216)**	**(31,127)**	1,190	12,589	13,779

During the second quarter of 2018, the commodity price risk management program resulted in a total loss of $31.1 million, compared to a total gain of $13.8 million for the comparable period of 2017. The fair value of financial derivative contracts are recorded in the financial statements. Unrealized gains and losses are the change in mark to market values or fair value of financial derivative contracts in place at the end of the quarter compared to the start of the quarter.

	Six months ended June 30					
($ thousands)	**2018**			2017		
	Realized gain (loss)	**Unrealized gain (loss)**	**Total gain (loss)**	Realized gain (loss)	Unrealized gain (loss)	Total gain (loss)
Natural gas	**3,495**	**23,624**	**27,119**	1,322	(31)	1,291
Condensate, oil and NGLs	**(17,771)**	**(34,596)**	**(52,367)**	(113)	32,914	32,801
Foreign exchange	**75**	**(109)**	**(34)**	—	—	—
Gain (loss) on financial derivatives	**(14,201)**	**(11,081)**	**(25,282)**	1,209	32,883	34,092

For the six months ended June 30, 2018, the commodity price risk management program resulted in a loss of $25.3 million compared to a realized gain of $34.1 million for the comparable period of 2017.

Price risk management gains on our physical delivery sale contracts totaled $7.3 million and $11.4 million for the three and six months ended June 30, 2018 compared to gains of $3.0 million and $5.4 million for the comparable periods of 2017. The mark to market value of the physical delivery sale contracts at June 30, 2018 was an asset of $9.2 million. The fair value of physical delivery sales contracts is not recorded on the financial statements but is recognized in net earnings as settled.

(a) Financial instruments

The following is a summary of financial derivatives contracts in place as at June 30, 2018:

	WTI fixed price swap		WTI fixed price swap		Currency derivatives	
Term [(1)]	Bbls/d	Cdn$/Bbl	Bbls/d	US$/Bbl	US$/Mo	CAD/USD
2018 remainder	7,200	71.25	1,000	50.24	2,000,000	1.3036
2019	3,343	74.16	—	—	—	—

[(1)] Table presented as weighted average volumes and prices.

	C$ WTI 3 Way Collar			
Term [(1)]	Bbls/d	Cdn$/Bbl	Cdn$/Bbl	Cdn$/Bbl
2019	500	65.80	78.80	91.42

[(1)] Table presented as weighted average volumes and prices.

	AECO-NYMEX basis swap		Chicago-NYMEX basis swap		Malin-NYMEX basis swap		AECO-Malin basis swap		Dawn-Nymex basis swap	
Term [(1)]	MMbtu/d	US$/ MMbtu	MMbtu/d	US$/ MMbtu	MMbtu/d	US$/ MMbtu	MMbtu/d	US$/ MMbtu	MMbtu/d	US$/ MMbtu
2018 remainder	16,630	(0.66)	10,000	(0.22)	13,315	(0.40)	3,315	0.68	10,027	(0.22)
2019	23,664	(0.86)	10,836	(0.25)	18,329	(0.40)	10,000	0.68	3,342	(0.26)
2020	47,500	(0.96)	15,000	(0.25)	11,667	(0.51)	8,333	0.68	20,000	(0.26)
2021	95,000	(0.98)	15,000	(0.24)	20,000	(0.66)	—	—	20,000	(0.26)
2022	95,000	(0.97)	12,493	(0.24)	16,658	(0.66)	—	—	16,658	(0.26)
2023	100,000	(1.01)	—	—	—	—	—	—	—	—
2024	100,000	(1.00)	—	—	—	—	—	—	—	—

[(1)] Table presented as weighted average volumes and prices.

	NYMEX fixed price swap		Dawn fixed price swap	
Term [(1)]	MMbtu/d	US$/MMbtu	MMbtu/d	US$/MMbtu
2018 remainder	49,973	2.96	6,630	2.50
2019	33,315	2.80	16,658	2.50

[(1)] Table presented as weighted average volumes and prices.

Subsequent to June 30, 2018 the following is a summary of financial derivatives that have been entered into:

	C$ WTI		C$ WTI 3 Way Collar			
Term (1)	Bbls/d	Cdn$/Bbl	Bbls/d	Cdn$/Bbl	Cdn$/Bbl	Cdn$/Bbl
2019	200	82.25	400	70.00	83.00	88.89

(1) Table presented as weighted average volumes and prices.

(b) Physical delivery sales contracts

The following is a summary of the physical delivery sales contracts in place as at June 30, 2018:

	AECO fixed price swap		Dawn fixed price swap	
Term (1)	GJ/d	Cdn$/GJ	GJ/d	Cdn$/GJ
2018 remainder	38,383	2.72	6,685	3.07

(1) Table presented as weighted average volumes and prices.

Royalties

	Three months ended June 30		Six months ended June 30	
($ thousands, except % and per Boe amounts)	**2018**	2017	**2018**	2017
Gross royalties	**6,811**	4,166	**11,309**	8,935
Gas cost allowance ("GCA")	**(2,500)**	(1,810)	**(5,166)**	(3,863)
Net royalties	**4,311**	2,356	**6,143**	5,072
Gross royalty % excluding physical delivery sales contracts(1)	**5.2**	5.5	**4.5**	5.6
Gross royalty % including physical delivery sales contracts	**5.0**	5.2	**4.3**	5.5
Net royalties per Boe	**1.31**	1.02	**0.94**	1.07

(1) Calculated as gross royalties as a % of petroleum and natural gas revenues excluding gains (losses) on physical delivery sales contracts.

For the three and six months ended June 30, 2018 , gross royalties increased 63% and 27% respectively as compared to the comparable periods of 2017 as a result of the production increases over the year. Gross royalties as a percentage of petroleum and natural gas revenues decreased as compared to the comparable periods of 2017 as a result of lower realized and benchmark gas prices, and a decrease in the percent of natural production exposed to AECO pricing as a result of the diversification of the gas sales portfolio.

The Company also receives GCA from the Crown, which reduces royalties to account for expenses incurred by NuVista to process and transport the Crown's portion of natural gas production. For the three and six months ended June 30, 2018, the 38% and 34% increase in GCA credits received compared to the comparative periods of 2017 is primarily due to the increased crown royalty payments made to the Crown as a result of increased production.

NuVista's physical price risk management activities impact reported average royalty rates as royalties are based on government market reference prices and not the Company's average realized prices that include price risk management activities.

In 2016, the provincial government of Alberta announced the key highlights of a proposed Modernized Royalty Framework ("MRF") that is effective for wells drilled after January 1, 2017. These highlights include a permanent structure providing a 5% royalty during the pre-payout period of conventional crude oil, natural gas, and NGL resources, then a higher royalty rate after the payout period. The payout period is governed by a revenue minus cost structure which focuses upon cost reduction and efficiency while staying nearly neutral on the average rate of return for any given play when compared to the prior royalty framework. Mature wells still receive reduced royalties, and there are no changes to the royalty structure of wells drilled prior to 2017 for a 10-year period from the royalty program's implementation date. The changes are not currently expected to have a material impact on NuVista's results of operations.

Transportation expenses

	Three months ended June 30		Six months ended June 30	
($ thousands, except per unit amounts)	**2018**	2017	**2018**	2017
Natural gas transportation expense	**10,434**	5,329	**19,161**	10,193
Condensate & NGL transportation expense	**579**	1,930	**1,294**	3,102
Total transportation expense	**11,013**	7,259	**20,455**	13,295
Natural gas transportation $/Mcf (1)	**0.89**	0.64	**0.81**	0.59
Condensate & NGL transportation $/Bbl	**0.54**	2.44	**0.62**	2.01
Total transportation $/Boe	**3.36**	3.13	**3.13**	2.82

(1) Includes total gas transportation from the plant gate to the final sales point.

For the three and six months ended June 30, 2018, transportation expenses on a total dollar and per Boe basis increased from the comparative periods of 2017 due to higher volumes and additional firm commitments for gas transportation. NuVista incurs transportation expenses on these gas volumes, however, the tolls are more than offset by the higher realized gas prices received at markets outside Alberta. This increase is partially offset by decreased condensate transportation expenses due to an increase in the proportion of condensate production flowing through third party liquids pipelines as opposed to being trucked. Compared to first quarter transportation expense of $9.4 million ($2.91/Boe), transportation expenses for the second quarter increased as a result of increased production and additional Malin long term fixed price firm service that came into effect in April 2018.

Operating expenses

	Three months ended June 30		Six months ended June 30	
($ thousands, except per unit amounts)	**2018**	2017	**2018**	2017
Operating expenses	**33,949**	24,694	**66,518**	50,475
Per Boe	**10.35**	10.66	**10.19**	10.69

For the three and six months ended June 30, 2018, operating expenses increased as a result of the increased production compared to the prior year comparative periods of 2017, while the per Boe costs decreased 3% and 5% respectively from the comparative periods due to increased production, operational efficiencies, and increased utilization of the Elmworth and Bilbo compressor stations. Compared to first quarter operating expenses of $32.6 million ($10.02/Boe), second quarter operating expenses per Boe increased slightly as a result of increased hauling rates associated with spring road conditions.

General and administrative expenses ("G&A")

	Three months ended June 30		Six months ended June 30	
($ thousands, except per Boe amounts)	**2018**	2017	**2018**	2017
Gross G&A expenses	**5,951**	5,284	**11,888**	10,866
Overhead recoveries	**(197)**	(64)	**(250)**	(353)
Capitalized G&A	**(1,238)**	(1,167)	**(2,534)**	(2,358)
Net G&A expenses	**4,516**	4,053	**9,104**	8,155
Gross G&A per Boe	**1.81**	2.28	**1.82**	2.30
Net G&A per Boe	**1.38**	1.75	**1.39**	1.73

As a result of continued focus on Wapiti Montney, NuVista has continued to realize efficiencies within G&A. For the three and six months ended June 30, 2018, gross G&A expenses have increased due to the slight increase in staff associated with the growing Montney production activities. On a per Boe basis, G&A expenses have decreased due to increased production as well as the Company's continued focus on cost control.

The Company's policy of allocating and capitalizing G&A expenses associated with new capital projects remained unchanged in 2017 and 2018. G&A capitalized and operating recoveries are in accordance with industry practice.

Share-based compensation expense

	Three months ended June 30		Six months ended June 30	
($ thousands)	**2018**	2017	**2018**	2017
Stock options	**1,003**	886	**1,959**	1,674
Director deferred share units	**705**	241	**588**	241
Restricted share awards	**500**	387	**951**	749
Performance share awards	**45**	—	**45**	—
Total	**2,253**	1,514	**3,543**	2,664

Share-based compensation expense relates to the amortization of the fair value of stock option awards, performance share awards ("PSA"), restricted share awards ("RSA") and accruals for future payments under the director deferred share unit ("DSU") plan. In the past the Company's share award incentive plan consisted of RSA's. Starting in the current quarter, the share award plan consists of both RSAs and PSAs, and during the three months ending June 30, 2018, the Company had an initial grant of PSAs.

The increase in share-based compensation for the three and six months ended June 30, 2018 compared to the comparable period of 2017 is due primarily to the increase in the weighted average fair value of stock options and RSAs granted in 2018, and an increase in the share price used to value DSUs over the comparable period of 2017.

Financing costs

	Three months ended June 30		Six months ended June 30	
($ thousands, except per Boe amounts)	**2018**	2017	**2018**	2017
Interest on long-term debt (credit facility)	**482**	804	**1,578**	1,366
Interest on senior unsecured notes (1)	**3,772**	1,866	**8,535**	3,670
Call premium on redemption of 2021 Notes	**—**	—	**6,562**	—
Interest expense	**4,254**	2,670	**16,675**	5,036
Accretion expense	**393**	360	**797**	796
Total financing costs	**4,647**	3,030	**17,472**	5,832
Interest expense per Boe	**1.30**	1.15	**2.55**	1.07
Total financing costs per Boe	**1.42**	1.31	**2.68**	1.24

(1) Year to date value includes $2.2 million of remaining accretion of carrying value to face value on redemption of 2021 Notes.

Interest expense on long-term debt includes interest standby charges on the Corporation's syndicated credit facilities. For the three months ended June 30, 2018 interest expense on long-term debt decreased 40% from the comparable period in 2017 due to lower average bank indebtedness throughout the period. For the six months ending June 30, 2018, interest expense on long-term debt increased from the comparable period of 2017 due to higher bank indebtedness in the first quarter of 2018. Average borrowing costs on long term debt for the three and six months ended June 30, 2018 were 3.3% and 3.4% compared to average borrowing costs of 2.7% and 2.9% for the comparative periods of 2017.

On March 2, 2018, the Company issued $220.0 million aggregate principal amount of 6.50% senior unsecured notes due March 2, 2023 ("2023 Notes"). Part of the proceeds from the 2023 Notes were used to redeem all of the

Company’s existing $70.0 million of 9.875% senior unsecured notes ("2021 Notes"), resulting in an agreed redemption call premium of $6.6 million, and $2.2 million of remaining accretion of the carrying value which is included in interest expense on a year to date basis, for a total incremental expense on payout of $8.8 million. See also the *Liquidity and Capital Resources* section in this MD&A.

Interest on the senior unsecured notes issued for the three and six months ended June 30, 2018, is for interest paid or accrued at the coupon rate to the end of the period on the 2021 and 2023 Notes. The effective interest rate on the 2021 Notes was 11.0%. The effective interest rate on the 2023 Notes is 7.0%. The carrying value of the 2023 Note at June 30, 2018 is $215.4 million.

Adjusted funds flow

A reconciliation of adjusted funds flow is presented in the following table:

	Three months ended June 30		Six months ended June 30	
($ thousands)	**2018**	2017	**2018**	2017
Cash provided by operating activities	**63,576**	40,298	**128,870**	76,324
Add back:				
Environmental remediation recovery	**—**	(2,550)	**—**	(2,550)
Asset retirement expenditures	**1,087**	1,156	**7,943**	11,059
Change in non-cash working capital	**4,809**	414	**(8,610)**	(2,261)
Adjusted funds flow[1]	**69,472**	39,318	**128,203**	82,572

[1] Refer to “Non-GAAP measurements”.

The tables below summarize operating netbacks for the three months ended June 30, 2018 and 2017:

	Three months ended June 30, 2018		Three months ended June 30, 2017	
($ thousands, except per Boe amounts)	**$**	**$/Boe**	$	$/Boe
Petroleum and natural gas revenues [1]	**137,131**	**41.82**	79,401	34.28
Realized gain (loss) on financial derivatives	**(8,911)**	**(2.72)**	1,190	0.51
	128,220	**39.10**	80,591	34.79
Royalties	**(4,311)**	**(1.31)**	(2,356)	(1.02)
Transportation expenses	**(11,013)**	**(3.36)**	(7,259)	(3.13)
Operating expenses	**(33,949)**	**(10.35)**	(24,694)	(10.66)
Operating netback[2]	**78,947**	**24.08**	46,282	19.98
General and administrative	**(4,516)**	**(1.38)**	(4,053)	(1.75)
Deferred share units	**(705)**	**(0.21)**	(241)	(0.10)
Interest expense	**(4,254)**	**(1.30)**	(2,670)	(1.15)
Adjusted funds flow netback[2]	**69,472**	**21.19**	39,318	16.98

[1] Includes price risk management gains of $7.3 million (2017 - $3.0 million gain) on physical delivery sales contracts.

[2] Refer to “Non-GAAP measurements”.

For the three months ended June 30, 2018, NuVista’s adjusted funds flow was $69.5 million ($0.40/share, basic), compared to $39.3 million ($0.23/share, basic) for the comparable period of 2017 and $58.7 million ($0.34/share, basic) in the first quarter of 2018. The increased adjusted funds flow in the second quarter of 2018 compared to the second quarter of 2017 is primarily a result of higher realized commodity pricing and higher production, partially offset by a loss on financial derivatives compared to a gain in the prior year comparative period, higher royalties, operating and transportation expenses associated with the increased production, and higher interest as a result of the increase in the principal of the senior unsecured notes payable from $70.0 million at 9.875% (2021 Notes) to $220.0 million at 6.50% (2023 Notes).

The tables below summarize operating netbacks for the six months ended June 30, 2018 and 2017:

	Six months ended June 30, 2018		Six months ended June 30, 2017	
($ thousands, except per Boe amounts)	**$**	**$/Boe**	$	$/Boe
Petroleum and natural gas revenues [1]	**261,887**	**40.12**	163,637	34.65
Realized gain (loss) on financial derivatives	**(14,201)**	**(2.18)**	1,209	0.26
	247,686	**37.94**	164,846	34.91
Royalties	**(6,143)**	**(0.94)**	(5,072)	(1.07)
Transportation expenses	**(20,455)**	**(3.13)**	(13,295)	(2.82)
Operating expenses	**(66,518)**	**(10.19)**	(50,475)	(10.69)
Operating netback[2]	**154,570**	**23.68**	96,004	20.33
General and administrative	**(9,104)**	**(1.39)**	(8,155)	(1.73)
Deferred share units	**(588)**	**(0.09)**	(241)	(0.05)
Interest expense	**(16,675)**	**(2.55)**	(5,036)	(1.07)
Adjusted funds flow netback[2]	**128,203**	**19.65**	82,572	17.48

[1] Includes price risk management gains of $11.4 million (2017 - $5.4 million gain) on physical delivery sales contracts.

[2] Refer to “Non-GAAP measurements”.

For the six months ended June 30, 2018, adjusted funds flow was $128.2 million ($0.74/share, basic) compared to $82.6 million ($0.48/share, basic) for the comparable period of 2017. Adjusted funds flow was higher than the comparable period of 2017 primarily due to higher production levels and realized commodity pricing, offset by a loss on financial derivatives as compared to a gain in the prior year comparative period, higher royalties, transportation, and operating expenses associated with the increased production, and higher interest as a result of the redemption of the 2021 Notes which resulted in interest and an agreed redemption call premium of $8.8 million, and the increase in the principal of the senior unsecured notes payable from $70.0 million at 9.875% (2021 Notes) to $220.0 million at 6.50% (2023 Notes).

Environmental remediation expense (recovery)

During the third quarter of 2015, NuVista identified a leak in a remote pipeline carrying oil emulsion in its non core area of Northwest Alberta. The pipeline was immediately shut down and NuVista’s emergency response plan was activated. In cooperation with local governmental regulators, First Nations, and with the assistance of qualified consultants, NuVista immediately commenced remediation and restoration activities. The Company recorded $9.3 million in environmental remediation expense in 2015. The majority of the remediation has been completed, $8.6 million has been spent and $0.7 million remains as accrued environmental remediation liabilities. Ongoing monitoring and reclamation will continue throughout 2018 and beyond. In the second quarter of 2017, the Company received insurance proceeds related to this event in the amount of $2.6 million. These proceeds have been recognized as environmental remediation recovery. Ongoing monitoring and reclamation will continue throughout 2018 and beyond.

The provision for accrued environmental remediation liability contains significant estimates and judgments about the scope, timing and costs of the work that will be required. The assumptions and estimates used are based on current information and are subject to revision in the future as further information becomes available to the Company.

Depletion, depreciation and amortization ("DD&A")

	Three months ended June 30		Six months ended June 30	
($ thousands, except per Boe amounts)	**2018**	2017	**2018**	2017
Depletion of oil and gas assets	**31,203**	23,303	**65,020**	47,107
Depreciation of fixed assets	**3,270**	3,448	**6,331**	6,843
DD&A expense	**34,473**	26,751	**71,351**	53,950
DD&A rate per Boe	**10.51**	11.55	**10.93**	11.43

DD&A expense for three and six months ended June 30, 2018 was $34.5 million ($10.51/Boe) compared to $26.8 million ($11.55/Boe) for the comparable period of 2017, and $36.9 million ($11.35/Boe) in the first quarter of 2018. At December 31, 2017, substantially all of the net book value of PP&E for cash generating units ("CGUs") excluding Wapiti Montney was depleted as a result of minimal reserves assigned to those CGUs in the year end reserve report. DD&A expense for the three and six months ended June 30, 2018 includes depletion expense of $0.8 million ($0.26/Boe) and $4.9 million ($0.75/Boe) primarily related to a change in estimate on asset retirement obligations. The change in estimate is an increase in asset retirement costs for wells with no remaining reserves. As a result, the full amount is included in depletion expense.

The Wapiti Montney DD&A rate per Boe for three and six months ended June 30, 2018 decreased to $10.30/Boe and $10.21/Boe respectively, compared to $11.05/Boe and $11.01for the comparable periods of 2017, and increased from $10.12/Boe compared to the first quarter of 2018. This decrease compared to 2017 is a result of improved year end reserves, while the 2% increase from the first quarter of 2018 is due to capital spending and production increases in second quarter compared to the first quarter.

At June 30, 2018 , there were no indicators of impairment or reversal of impairment identified on any of the Company's CGU's within property, plant & equipment.

Exploration and evaluation ("E&E") expense

	Three months ended June 30		Six months ended June 30	
($ thousands, except per Boe amounts)	**2018**	2017	**2018**	2017
Exploration and evaluation expense	**1,454**	44	**1,454**	44
Per Boe	**0.44**	0.02	**0.22**	0.01

Exploration and evaluation expense relates to the cost of mineral land expiries that were classified as E&E assets.

Asset retirement obligations

($ thousands)	**June 30, 2018**	December 31, 2017
Balance, January 1	**72,430**	75,463
Accretion expense	**797**	1,524
Liabilities incurred	**2,021**	3,698
Liabilities disposed	**(14)**	(3,272)
Change in estimates and discount rate	**5,493**	4,830
Liabilities settled	**(7,943)**	(9,813)
Balance, end of period	**72,784**	72,430
Expected to be incurred within one year	**15,400**	14,250
Expected to be incurred beyond one year	**57,384**	58,180

Asset retirement obligations ("ARO") are based on estimated costs to reclaim and abandon ownership interests in oil and natural gas assets including well sites, gathering systems and processing facilities. At June 30, 2018, NuVista had an ARO balance of $72.8 million as compared to $72.4 million as at December 31, 2017. The liability was discounted using a risk free discount rate of 2.2% at June 30, 2018 (December 31, 2017 – 2.4%). At June 30, 2018, the estimated total undiscounted and uninflated amount of cash flow required to settle NuVista's ARO was $74.8 million (December 31, 2017 – $75.9 million). The majority of the costs are expected to be incurred between 2019 and 2037. Actual ARO expenditures for the six months ended June 30, 2018 were $7.9 million compared to $9.8 million for the year ended December 31, 2017.

There are uncertainties related to asset retirement obligations and the impact on the financial statements could be material, as the eventual timing and expected costs to settle these obligations could differ from our estimates. The main factors that could cause expected costs to differ are changes to laws, regulations, reserve estimates, costs and technology. Any reclamation or abandonment expenditures will generally be funded from cash flow from operating activities.

Capital expenditures

	Three months ended June 30				Six months ended June 30			
($ thousands, except % amounts)	**2018**	% of total	2017	% of total	**2018**	% of total	2017	% of total
Exploration and evaluation assets and property plant and equipment [(1)]								
Land and retention costs	**1,785**	2	276	—	**1,871**	1	408	—
Geological and geophysical	**1,741**	2	1,370	2	**3,190**	2	2,605	2
Drilling and completion	**59,043**	72	52,421	76	**154,421**	78	139,660	79
Facilities and equipment	**19,674**	24	14,892	22	**37,700**	19	33,723	19
Corporate and other	**79**	—	291	—	**360**	—	266	—
Total capital expenditures	**82,322**		69,250		**197,542**		176,662	

(1) Includes cash paid capital, excludes non cash items.

Capital expenditures for the three and six months ended June 30, 2018 were higher than the comparative periods in 2017 due to increased drilling activity, while continuing to realize continued reductions in drilling and completion costs as a result of efficiencies gained from multi-well pad drilling. The Company focused 72% of its capital expenditures on drilling and completion activities, with 24% on facilities and equipment, primarily related to the active winter drilling program and bringing wells on production in the period. The Company expects full year 2018 capital expenditures to be in the range of $270 - $310 million.

Of the $197.5 million capital spent in 2018, $194.2 million was spent on property, plant and equipment expenditures, and $3.3 million was spent on exploration and evaluation expenditures.

Dispositions

For the six months ended June 30, 2018, there was a minor property disposition with cash proceeds of $nil, resulting in a loss of $0.1 million as compared property dispositions with cash proceeds of $0.8 million in the comparable period of 2017, resulting in a gain of $3.3 million.

Deferred income taxes

For the three and six months ended June 30, 2018, the provision for income taxes was an expense of $2.9 million, and $11.7 million compared to an expense of nil in the comparable periods of 2017. At June 30, 2018, the Company recognized the full benefit of the Company's tax pool balances exceeding accounting carrying values with a deferred tax asset of $7.0 million. With total forecast cash flows net of future development capital on a total proved basis exceeding the Company's tax pools, the Company is forecast to utilize all of the existing tax pools and as a result has recognized a deferred tax asset.

Elimination of deficit

At the Company's annual general meeting on May 8, 2018, shareholders approved a resolution to reduce share capital for accounting purposes, without payment of or a reduction to stated or paid-up capital, by the amount of the deficit on December 31, 2017 in the amount of $462.4 million.

Net earnings

	Three months ended June 30		Six months ended June 30	
($ thousands, except per share amounts)	**2018**	2017	**2018**	2017
Net earnings	**6,322**	25,767	**28,693**	64,084
Per share - basic	**0.04**	0.15	**0.16**	0.37
Per share - diluted	**0.04**	0.15	**0.16**	0.37

The decrease in net earnings for the three and six months ended June 30, 2018 compared to the prior year comparative periods is primarily a result of the increased adjusted funds flow offset by decreased unrealized hedging gains, increased DD&A and the incremental interest on the higher principal balance of the 2023 Notes.

Liquidity and capital resources

Long-term debt (credit facility)

At June 30, 2018, the Company had a $310 million (December 31, 2017 - $310 million) extendible revolving term credit facility available from a syndicate of Canadian chartered banks. Borrowing under the credit facility may be made by prime loans, bankers' acceptances and/or US libor advances. These advances bear interest at the bank's prime rate and/or at money market rates plus a borrowing margin. The credit facility is secured by a first floating charge debenture, general assignment of book debts and NuVista's oil and natural gas properties and equipment. The credit facility has a 364-day revolving period and is subject to an annual review by the lenders, at which time a lender can extend the revolving period or can request conversion to a one year term loan. During the revolving period, a review of the maximum borrowing amount occurs semi-annually on October 31 and April 30. During the term period, no principal payments would be required until a year after the revolving period matures on the annual renewal date of April 30, in the event the credit facility is reduced or not renewed. As such, the credit facility is classified as long-term. The credit facility does not contain any financial covenants but NuVista is subject to various industry standard non-financial covenants. Compliance with these covenants is monitored on a regular basis and as at June 30, 2018, NuVista was in compliance with all covenants.

The annual review was completed in April 2018 with no changes to the amount and terms of the credit facility. The next semi-annual review is scheduled for on or before October 31, 2018.

Senior unsecured notes

On March 2, 2018, the Company issued $220.0 million aggregate principal amount of 6.50% senior unsecured notes due March 2, 2023 ("2023 Notes"). Proceeds net of costs amounted to $215.1 million. Interest is payable semi-annually in arrears. The 2023 Notes are fully and unconditionally guaranteed as to the payment of principal and interest, on a senior unsecured basis by the Company. There are no maintenance or financial covenants.

The 2023 Notes are non-callable by the Company prior to March 2, 2020. At any time on or after March 2, 2020, the Company may redeem all or part of the 2023 Notes at the redemption prices set forth in the table below plus any accrued and unpaid interest:

12 month period ended:	Percentage
March 2, 2021	103.250%
March 2, 2022	101.625%
March 2, 2023	100.000%

If a change of control occurs, each holder of the 2023 Notes will have the right to require the Company to purchase all or any part of that holder's 2023 Notes for an amount in cash equal to 101% of the aggregate principal repurchased plus accrued and unpaid interest.

On June 22, 2016, the Company issued $70.0 million of 9.875% senior unsecured notes ("2021 Notes") with a 5 year term by way of private placement. Proceeds net of discount and costs amounted to $66.9 million. Interest is payable in equal quarterly installments in arrears. The 2021 Notes are fully and unconditionally guaranteed as to the payment of principal and interest, on a senior unsecured basis by the Company. There are no maintenance financial covenants. On March 2, 2018, part of the proceeds from the 2023 Notes were used to redeem all of the Company's existing 2021 Notes. The full aggregate principal amount of $70.0 million was redeemed resulting in an agreed redemption call premium of $6.6 million and $2.2 million of remaining accretion of the carrying value to face value of the 2021 Notes which is included in year to date interest expense, for a total incremental expense on payout of $8.8 million.

Net debt (2)

The following is a summary of market capitalization, net debt, and net debt to annualized current quarter adjusted funds flow:

($ thousands)	**June 30, 2018**	December 31, 2017
Common shares outstanding	**174,881**	174,004
Share price(1)	**9.12**	8.02
Total market capitalization	**1,594,915**	1,395,512
Adjusted working capital deficit(2)	**39,927**	2,784
Senior unsecured notes	**215,414**	67,680
Long-term debt (credit facility)	**13,103**	125,725
Net debt (2)	**268,444**	196,189
Annualized current quarter adjusted funds flow(2)	**277,888**	303,728
Net debt to annualized current quarter adjusted funds flow(2)	**1.0**	0.6

(1) Represents the closing share price on the Toronto Stock Exchange on the last trading day of the period.
(2) Refer to the "Non-GAAP measurements".

As at June 30, 2018, net debt was $268.4 million, resulting in a net debt to annualized current quarter adjusted funds flow ratio of 1.0x. NuVista's long term strategy is to maintain a net debt to annualized current quarter adjusted funds flow ratio of approximately 1.5x. The actual ratio may fluctuate on a quarterly basis above or below targeted levels due to a number of factors including facility outages, commodity prices and the timing of acquisitions and dispositions. At June 30, 2018, NuVista had an adjusted working capital deficit of $39.9 million. Adjusted working capital is current assets less current liabilities excluding the current portion of the fair value of the financial derivative assets and liabilities and the current portion of asset retirement obligations. The Company believes it is appropriate to exclude these amounts when assessing financial leverage. At June 30, 2018, NuVista had drawn $13.1 million on its long-term debt (credit facility) and had outstanding letters of credit of $5.7 million which reduce the credit available on the credit facility, leaving $291.2 million of unused credit facility capacity based on the committed credit facility of $310.0 million.

NuVista plans to monitor its 2018 business plan and adjust its budgeted capital program of $270 - $310 million in the context of commodity prices and net debt levels. NuVista plans to finance its 2018 capital program with adjusted funds flow, proceeds from the senior unsecured note issuance, and the credit facility.

As at June 30, 2018, there were 174.9 million common shares outstanding. In addition, there were 6.2 million stock options with an average exercise price of $7.65 per option and 0.6 million RSAs and 0.1 million PSAs outstanding.

Contractual obligations and commitments

NuVista enters into contract obligations as part of conducting business. The following is a summary of NuVista's contractual obligations and commitments as at June 30, 2018:

($ thousands)	**Total**	2018	2019	2020	2021	2022	Thereafter
Transportation and processing [1]	**954,393**	43,914	95,064	97,318	104,255	104,243	509,599
Office lease	**13,720**	907	1,814	1,826	1,887	1,893	5,393
Total commitments	**968,113**	44,821	96,878	99,144	106,142	106,136	514,992

[1] Certain of the transportation and processing commitments are secured by outstanding letters of credit of $5.3 million at June 30, 2018 (December 31, 2017 - $12.8 million).

Off "balance sheet" arrangements

NuVista has certain lease arrangements, all of which are reflected in the contractual obligations and commitments table, which were entered into in the normal course of operations. All leases have been treated as operating leases whereby the lease payments are included in operating expenses or general and administrative expenses depending on the nature of the lease.

Quarterly financial information

The following table highlights NuVista's performance for the eight quarterly reporting periods from Sep 30, 2016 to June 30, 2018:

($ thousands, except	**2018**		2017				2016	
per share amounts)	**Jun 30**	Mar 31	Dec 31	Sep 30	Jun 30	Mar 31	Dec 31	Sep 30
Production (Boe/d)	**36,035**	36,099	37,435	29,405	25,454	26,731	24,716	24,898
Petroleum and natural gas revenues	**137,131**	124,756	131,009	83,100	79,401	84,236	74,538	65,155
Net earnings (loss)	**6,322**	22,371	34,651	(4,366)	25,767	38,317	1,135	2,079
Net earnings (loss)								
Per basic and diluted share	**0.04**	0.13	0.20	(0.03)	0.15	0.22	0.01	0.01
Adjusted funds flow	**69,472**	58,732	75,932	41,526	39,318	43,254	40,697	31,237
Per basic and diluted share	**0.40**	0.34	0.44	0.24	0.23	0.25	0.24	0.20

NuVista's Montney production volumes have been increasing with substantially all of the Company's capital expenditures allocated to Wapiti Montney and successful drilling and production performance in that core area. Production from Wapiti Montney in 2018 is 99% of total production. Total Company production increases since 2016 have more than offset production sold in non core property dispositions. Over the prior eight quarters, quarterly revenue has been in a range of $65.2 million to $137.1 million with revenue primarily influenced by production volumes and commodity prices. Net earnings (losses) have been in a range of a net loss of $4.4 million to net earnings of $38.3 million with earnings primarily influenced by impairments, gains and losses from disposal of assets, production volumes, commodity prices, realized and unrealized gains and losses on financial derivatives and deferred income taxes.

Critical accounting estimates

Management is required to make judgments, assumptions and estimates in applying its accounting policies which have significant impact on the financial results of NuVista. The following outline the accounting policies involving the use of estimates that are critical to understanding the financial condition and results of operations of NuVista.

(a) ***Oil and natural gas reserves*** – Oil and natural gas reserves, as defined by the Canadian Securities Administrators in National Instrument 51-101 with reference to the Canadian Oil and Natural Gas Evaluation Handbook, are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated reserves.

An independent reserve evaluator using all available geological and reservoir data as well as historical production data has prepared NuVista's oil and natural gas reserve estimates. Estimates are reviewed and revised as appropriate. Revisions occur as a result of changes in prices, costs, fiscal regimes, reservoir performance or a change in NuVista's development plans.

(b) ***Depletion, depreciation, amortization and impairment*** – Property, plant and equipment is measured at cost less accumulated depletion, depreciation, amortization and impairment losses. The net carrying value of property, plant and equipment and estimated future development costs is depleted using the unit-of-production method based on estimated proved and probable reserves. Changes in estimated proved and probable reserves or future development costs have a direct impact in the calculation of depletion expense.

NuVista is required to use judgment when designating the nature of oil and gas activities as exploration and evaluation assets or development and production assets within property, plant and equipment. Exploration and evaluation assets and development and production assets are aggregated into CGUs based on their ability to generate largely independent cash flows. The allocation of NuVista's assets into CGUs requires significant judgment with respect to use of shared infrastructure, existence of active markets for NuVista's products and the way in which management monitors operations.

Exploration and evaluation expenditures relating to activities to explore and evaluate oil and natural gas properties are initially capitalized and include costs associated with the acquisition of licenses, technical services and studies, seismic acquisition, exploration drilling and testing, directly attributable overhead and administration expenses, and costs associated with retiring the assets. Exploration and evaluation assets are carried forward until technical feasibility and commercial viability of extracting a mineral resource is determined. Technical feasibility and commercial viability of extracting a mineral resource is considered to be determined when proved and/or probable reserves are determined to exist. E&E assets are tested for impairment when facts and circumstances suggest that the carrying amount of E&E assets may exceed their recoverable amount, by comparing the relevant costs to the fair value of CGUs, aggregated at the segment level. The determination of the fair value of CGUs requires the use of assumptions and estimates including quantities of recoverable reserves, production quantities, future commodity prices and development and operating costs. Changes in any of these assumptions, such as a downward revision in reserves, decrease in commodity prices or increase in costs, could impact the fair value.

NuVista assesses property, plant and equipment for impairment whenever events or changes in circumstances indicate that the carrying value of an asset or group of assets may not be recoverable. If any such indication of impairment exists, NuVista performs an impairment test related to the specific CGU. The determination of fair value of CGUs requires the use of assumptions and estimates including quantities of recoverable reserves, production quantities, future commodity prices and development and operating costs. Changes in any of these assumptions, such as a downward revision in reserves, decrease in commodity prices or increase in costs, could impact the fair value.

(c) ***Asset retirement obligations*** – The asset retirement obligations are estimated based on existing laws, contracts or other policies. The fair value of the obligation is based on estimated future costs for abandonments and reclamations discounted at a risk free rate. The costs are included in property, plant and equipment and amortized over its useful life. The liability is adjusted each reporting period to reflect the passage of time, with the accretion expense charged to net earnings, and for revisions to the estimated future cash flows. By their nature, these estimates are subject to measurement uncertainty and the impact on the financial statements could be material.

(d) ***Income taxes*** – The determination of income and other tax liabilities requires interpretation of complex laws and regulations often involving multiple jurisdictions. 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.

Update on financial reporting matters

Adopted new accounting standards

Revenue recognition

NuVista adopted IFRS 15 - Revenue from Contracts with Customers with a date of initial application of January 1, 2018. IFRS 15 specifies how and when an IFRS reporter will recognize revenue as well as requiring enhanced disclosures about revenue. 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.

NuVista's management reviewed its revenue streams and major contracts with customers and concluded that there were no material changes to its net income or in the timing of when revenue is recognized. As a result, no adjustments were required in the January 1, 2018 opening statement of financial position. The additional disclosures required by IFRS 15 are provided in Note 12 of the condensed interim financial statements.

NuVista’s petroleum and natural gas revenue from the sale of natural gas, condensate, and NGLs are based on the consideration specified in contracts with customers. NuVista recognizes revenue when it transfers control of the product to the customer. This is generally at the point in time when the customer obtains legal title to the product which is when it is physically transferred to the pipeline or other transportation method agreed upon and collection is reasonably assured. The amount of revenue recognized is based on the consideration specified in the contract. As a result of various marketing arrangements, NuVista will give up title to their commodity to a third party marketing company who will deliver the product to the end customer using NuVista's pipeline capacity. This revenue is shown separate as transportation revenue. NuVista evaluates its arrangements with third parties and partners to determine if NuVista is acting as the principal or as an agent. NuVista is considered the principal in a transaction when it has primary responsibility for the transaction. If NuVista acts in the capacity of an agent rather than as a principal in a transaction, then the revenue is recognized on a net basis, only reflecting the fee, if any, realized by NuVista from the transaction. The transaction price for variable price contracts is based on a representative commodity price index, and may be adjusted for quality, location, delivery method, or other factors depending on the agreed upon terms of the contract. The amount of revenue recorded can vary depending on the grade, quality and quantities of natural gas, condensate or NGLs transferred to customers. Market conditions, which impact NuVista's ability to negotiate certain components of the transaction price, can also cause the amount of revenue recorded to fluctuate from period to period. Tariffs, tolls and fees charged to other entities for use of pipelines and facilities owned by NuVista are evaluated by management to determine if these originate from contracts with customers or from incidental or collaborative arrangements. Tariffs, tolls and fees charged to other entities that are from contracts with customers are recognized in revenue when the related services are provided.

Financial instruments

NuVista adopted IFRS 9 - Financial Instruments, on January 1, 2018 using the retrospective method. The adoption of this standard did not result in a change in the recognition or measurement of any of the Company's financial instruments on transition. IFRS 9 contains three principal classification categories for financial assets: measured at amortized cost, fair value through other comprehensive income ("FVOCI"); or fair value through profit or loss ("FVTPL"). Under IFRS 9, where the fair value option is applied to financial liabilities, any change in fair value resulting from an entity's own credit risk is recorded through other comprehensive income or loss rather than net income or loss. The classification of financial assets under IFRS 9 is generally based on the business model in which a financial asset is managed and its contractual cash flow characteristics. A financial asset is subsequently measured at amortized cost if it meets both of the following conditions: a) the asset is held with a business model whose objective is to hold assets to collect contractual cash flows; and b) the contractual terms of the financial assets give rise to cash flows on specified dates that are solely payments of principal and interest on principal amounts outstanding. Financial assets that meet criteria (b) above that are held within a business model whose objective is achieved by both collecting contractual cash flows and selling financial assets is subsequently measured at FVOCI. All other financial assets are subsequently measured at FVTPL. There was no change to the measurement categories of financial liabilities. IFRS 9 eliminates the previous IAS 39 categories of held to maturity, loans and receivables and available for sale. The new standard also introduces an expected credit loss model for evaluating impairment of financial assets, which results in credit losses being recognized earlier than under IAS 39. In addition, IFRS 9 provides a hedge accounting model that is more in line with risk management activities. The Company currently does not apply hedge accounting to its derivative contracts. Accounts receivable and prepaid expenses continue to be measured at amortized cost and are now classified as “amortized cost". There was no change to the Company's classification of accounts payable and accrued liabilities or long term debt and senior unsecured notes which are classified as “other financial liabilities” and are measured at amortized cost.

Future accounting changes

In January 2016, the IASB issued IFRS 16 "Leases" which replaces IAS 17 "Leases". For lessees applying IFRS 16, a single recognition and measurement 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 for IFRS 15 "Revenue from Contracts with Customers". IFRS 16 will be applied by NuVista on January 1, 2019 and the Company is currently in the process of reviewing and analyzing contracts that fall into the scope of the new standard. The extent of the impact of the adoption of the standard has not yet been determined.

Update on regulatory matters

Environmental

In the fourth quarter of 2015, 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. NuVista does not expect the Climate Leadership Plan to have a material impact on the cost of operating its properties.

The oil and natural gas industry is currently subject to environmental regulations pursuant to a variety of federal, provincial, and local laws and regulation. Environmental legislation provides for, among other things, restrictions and prohibitions on emissions, releases or spills of various substances produced in association with oil and natural gas operations. Compliance with such legislation can require significant expenditures and a breach may result in the imposition of fines and penalties, some of which may be material. Environmental legislation is evolving in a manner expected to result in stricter standards and enforcement, as well as larger fines and environmental liability. No assurance can be given that the application of environmental laws to the business and operations of NuVista will not result in a limitation of production or a material increase in the costs of operating, development, or exploration activities or otherwise adversely affect NuVista's financial condition, results of operations, or prospects.

NuVista utilizes monitoring and reporting programs, as well as inspections and audits for environmental, health, and safety performance that are designed to provide assurance that environmental and regulatory standards are met. In the event of unknown or unforeseeable environmental impacts arising from its operations, NuVista may be subject to remedial and litigation costs. Contingency plans are in place for a timely response to environmental events and for the utilization of remediation/reclamation strategies to restore the environment in the event of such impacts.

Given the evolving nature of climate change discussion, the regulation of emissions of greenhouse gases ("GHGs") and potential federal and provincial GHG commitments, NuVista is unable to predict the impact on its operations and financial condition at this time. It is possible that NuVista could face increases in operating and capital costs in order to comply with augmented greenhouse gas emissions legislation.

Further information regarding environmental and climate change regulations and current provincial royalty and incentive programs are contained in our Annual Information Form under the Industry Conditions section for the year ended December 31, 2017.

Disclosure controls and internal controls over financial reporting

NuVista's President and Chief Executive Officer ("CEO") and Vice President, Finance and Chief Financial Officer ("CFO") are responsible for establishing and maintaining disclosure controls and procedures and internal controls over financial reporting as defined in National Instrument 52-109. NuVista's CEO and CFO have designed disclosure controls and procedures, or caused them to be designed under their supervision, to provide reasonable assurance that information required to be disclosed by NuVista in its 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 is accumulated and communicated to NuVista's management, including its certifying officers, as appropriate to allow timely decisions regarding required disclosure. The CEO and CFO have concluded, based on their evaluation as of the end of the period covered by the interim filings that the Company's disclosure controls and procedures are effective.

The CEO and CFO have also designed internal controls over financial reporting, or caused them to be designed under their supervision, to provide reasonable assurance regarding the reliability of NuVista's financial reporting and the preparation of financial statements for external purposes in accordance with GAAP and includes those policies and procedures that:

(a) pertain to the maintenance of records that in reasonable detail accurately and fairly reflect the transactions and dispositions of the assets of NuVista;

(b) are designed to provide reasonable assurance that transactions are recorded as necessary to permit preparation of the financial statements in accordance with GAAP, and that receipts and expenditures of NuVista are being made only in accordance with authorizations of management and directors of NuVista; and

(c) are designed to provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of NuVista's assets that could have a material effect on the annual financial statements.

NuVista has designed its internal controls over financial reporting based on the Committee of Sponsoring Organizations of the Treadway Commission (2013). During the three months ended June 30, 2018, there have been no changes to NuVista's internal controls over financial reporting that have materially or are reasonably likely to materially affect the internal controls over financial reporting; the CEO and CFO have concluded that the internal controls over financial reporting are effective.

Because of their inherent limitations, disclosure controls and procedures and internal control over financial reporting may not prevent or detect misstatements, error or fraud. Control systems, no matter how well conceived or operated, can provide only reasonable, not absolute assurance, that the objectives of the control system are met.

Assessment of business risks

The following are the primary risks associated with the business of NuVista. Most of these risks are similar to those affecting others in the conventional oil and natural gas sector. NuVista's financial position and results of operations are directly impacted by these factors:

- Operational risk associated with the production of oil and natural gas;
- Operational risk associated with third party facility outages and downtime;
- Reserves risk with respect to the quantity and quality of recoverable reserves;
- Commodity risk as crude oil and natural gas prices and differentials fluctuate due to market forces;
- Financial risk such as volatility of the Cdn/US dollar exchange rate, interest rates and debt service obligations;
- Risk associated with the re-negotiation of NuVista's credit facility and the continued participation of NuVista's lenders;
- Market risk relating to the availability of transportation systems to move the product to market;
- Environmental and safety risk associated with well operations and production facilities;
- Changing government regulations relating to royalty legislation, income tax laws, incentive programs, operating practices, fracturing regulations and environmental protection relating to the oil and natural gas industry; and
- Labour risks related to availability, productivity and retention of qualified personnel.

NuVista seeks to mitigate these risks by:

- Acquiring properties with established production trends to reduce technical uncertainty as well as undeveloped land with development potential;
- Maintaining a low cost structure to maximize product netbacks and reduce impact of commodity price cycles;
- Diversifying properties to mitigate individual property and well risk;
- Maintaining product mix to balance exposure to commodity prices;
- Conducting rigorous reviews of all property acquisitions;
- Monitoring pricing trends and developing a mix of contractual arrangements for the marketing of products with creditworthy counterparties;
- Maintaining a price risk management program to manage commodity prices and foreign exchange currency rates risk and transacting with creditworthy counterparties;
- Ensuring strong third-party operators for non-operated properties;
- Adhering to NuVista's safety program and keeping abreast of current operating best practices;
- Keeping informed of proposed changes in regulations and laws to properly respond to and plan for the effects that these changes may have on our operations;
- Carrying industry standard insurance to cover losses;
- Establishing and maintaining adequate cash resources to fund future abandonment and site restoration costs;
- Closely monitoring commodity prices and capital programs to manage financial leverage; and
- Monitoring the bank and equity markets to understand how changes in the capital market may impact NuVista's business plan.

Information regarding risk factors associated with the business of NuVista and how NuVista seeks to mitigate these risks are contained in our Annual Information Form under the Risk Factors Section for the year ended December 31, 2017.

2018 Outlook: annual guidance reaffirmed

As previously stated, production for the third quarter of 2018 is expected to be impacted by 2,350 Boe/d due to the deferral of the planned Keyera Simonette gas plant outage into the third quarter, and also the unplanned SemCAMS K3 gas plant outage which occurred in July. Based on this downtime, our updated annual production guidance for 2018 can be tightened from the range of 35,000 - 40,000 Boe/d to 36,000 - 38,000 Boe/d. Underlying production outside of outage periods is proceeding at planned levels with run rates over 37,500 Boe/d. Previous adjusted funds flow guidance for 2018 of $210 - $240 million is increased to $240 - $260 million as a result of higher condensate proportions and favorable strip pricing[1]. Our 2018 capital plan remains unchanged, expecting to reach the upper portion of our guidance range of $270 - $310 million.

[1] Strip pricing assumptions for 2H 2018: WTI $US 69.00/Bbl, Nymex Gas $US 2.85/MMBTU, Fx 1.31