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") 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 March 9, 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** on or before March 30, 2018.

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; the timing, allocation and efficiency of NuVista’s capital program and the results therefrom; the anticipated potential and growth opportunities associated with NuVista’s asset base; 2018 capital spending, production, adjusted funds flow, and net debt to adjusted funds flow ratio; 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 flow from operating activities as per the statement of cash flows before changes in non-cash working capital, asset retirement expenditures, note receivable allowance (recovery) 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 expenses calculated on a Boe basis. Net debt is calculated as long-term debt plus senior unsecured notes plus adjusted working capital. Adjusted working capital 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 December 31		Year ended December 31	
Number of wells	**2017**	2016	**2017**	2016
Wells drilled - gross & net [(1)]	**4.0**	7.0	**30.0**	20.0
Wells completed - gross & net [(2)]	**3.0**	3.0	**32.0**	18.0
Wells brought on production - gross & net [(3)]	**2.0**	5.0	**30.0**	21.0

(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 December 31, 2017, NuVista drilled 4 natural gas wells compared to 7 natural gas wells in the comparable period of 2016. For the year ended December 31 2017, NuVista drilled 30 natural gas wells compared to 20 natural gas wells in the comparable period of 2016. All wells in 2017 and 2016 were drilled in NuVista's Wapiti Montney operating area with a 100% success rate and an average working interest of 100%.

Dispositions

NuVista completed minor asset dispositions in the three months and year ended December 31, 2017, in NuVista's non core operating areas.

During the second quarter of 2016, NuVista disposed of its assets in the Wapiti Sweet operating area with combined production at the time of sale of approximately 3,200 Boe/d.

Production

	Three months ended December 31			Year ended December 31		
	2017	2016	% Change	**2017**	2016	% Change
Natural gas (Mcf/d)	**131,703**	96,692	36	**106,992**	89,773	19
Condensate & oil (Bbls/d)	**13,087**	7,057	85	**9,841**	6,764	45
Natural gas liquids ("NGLs") (Bbls/d)	**2,397**	1,432	67	**1,879**	1,180	59
Subtotal (Boe/d)	**37,435**	24,605	52	**29,552**	22,907	29
Dispositions (Boe/d) [(1)]	**—**	111	(100)	**231**	1,731	(87)
Total production (Boe/d)	**37,435**	24,716	51	**29,783**	24,638	21
Condensate, oil & NGLs weighting [(2) & (3)]	**41%**	35%		**39%**	34%	
Condensate & oil weighting [(3)]	**35%**	29%		**33%**	28%	

(1) Production from properties disposed in the current or prior period.
(2) NGLs include butane, propane and ethane.
(3) Product weighting is based on total production.

Production weighting % by area	Three months ended December 31 **2017**	 2016	Year ended December 31 **2017**	 2016
Wapiti Montney	**99%**	96%	**97%**	89%
Non core	**1%**	4%	**2%**	4%
Dispositions	**—%**	—%	**1%**	7%

Production for the three months ended December 31, 2017 increased 51% over the comparative period 2016, driven by strong results from the Company's continued successful execution of the Montney development program. Production increased 27% from third quarter 2017 production of 29,405 Boe/d with the tie in of 20 new wells throughout the third and fourth quarters. Condensate & oil volumes increased from 29% of total production volumes in the fourth quarter of 2016 to 35% of total production volumes for the fourth quarter of 2017, with new wells brought on stream achieving higher condensate-to-gas ratios (CGRs).

For the year ended December 31, 2017, NuVista's average production increased 21% over the comparative period of 2016 as a result of the production increases from new development in the Montney, offset by planned and unplanned outages and production sold in property dispositions in 2016.

Revenue

Petroleum and natural gas revenue ($ thousands)	Three months ended December 31 **2017**		 2016		Year ended December 31 **2017**		 2016	
Natural gas [1]	**41,633**	**32%**	33,175	45%	**141,310**	**37%**	125,591	49%
Condensate & oil	**82,299**	**63%**	38,866	52%	**219,561**	**58%**	125,646	49%
Other NGL's [2]	**7,077**	**5%**	2,497	3%	**16,875**	**4%**	6,015	2%
Total petroleum and natural gas revenues	**131,009**	**100%**	74,538	100%	**377,746**	**99%**	257,252	100%

(1) Natural gas revenue includes price risk management gains and losses on physical delivery sale contracts. For the three months ended December 31, 2017, our physical delivery sales contracts totaled a $8.9 million gain (2016 – $4.3 million gain). For the year ended December 31, 2017, our physical delivery sales contracts totaled a $21.4 million gain (2016 - $32.6 million gain).

(2) Includes butane, propane, and ethane.

	Three months ended December 31		Year ended December 31	
	2017	2016	**2017**	2016
Realized selling prices (1) & (2)				
Natural gas ($/Mcf)	**3.44**	3.74	**3.58**	3.54
Condensate & oil ($/Bbl)	**68.36**	58.21	**61.01**	49.81
NGLs ($/Bbl)	**32.09**	19.35	**24.42**	10.43
Oil equivalent ($/Boe)	**38.04**	32.78	**34.75**	28.53
Benchmark pricing				
Natural gas - AECO (daily) ($/GJ)	**1.60**	2.93	**2.04**	2.05
Natural gas - AECO (monthly) ($/GJ)	**1.85**	2.67	**2.30**	1.98
Natural gas - NYMEX (monthly) (US$/MMbtu)	**2.93**	2.98	**3.11**	2.46
Natural gas - Chicago Citygate (monthly) (US$/MMbtu)	**2.92**	3.00	**3.04**	2.49
Natural gas - Dawn (daily) (US$/MMbtu)	**2.95**	3.16	**3.04**	2.55
Oil - WTI (US$/Bbl)	**55.40**	49.29	**50.95**	43.32
Oil - Edmonton Par - (Cdn$/Bbl)	**69.07**	61.60	**62.88**	52.90
Exchange rate - (Cdn$/US$)	**1.27**	1.33	**1.30**	1.33

(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.

(2) The average liquids selling price is net of tariffs and fractionation fees.

Petroleum and natural gas revenue

For the three months ended December 31, 2017, petroleum and natural gas revenue increased 76% over the comparable period of 2016, due primarily to a 51% increase in production, a higher weighting of condensate in the production mix, and a 16% increase in realized prices for the quarter. For the year ended December 31, 2017, petroleum and natural gas revenue increased 47% over the comparable period of 2016, due primarily to a 21% increase in production and a 22% increase in realized selling prices.

Condensate & oil weighting of 35% of total production in the fourth quarter of 2017, amounted to 63% of total petroleum and natural gas revenue, due primarily to a 17% increase in realized condensate & oil selling prices which is consistent with a 12% increase in the WTI benchmark for the period.

Natural gas revenue

For the three months ended December 31, 2017, natural gas revenue increased 25% over the comparable period of 2016, due to a 37% increase in production offsetting a 8% decrease in realized selling prices. For the year ended December 31, 2017, natural gas revenue increased 13% over the comparable period of 2016, due primarily to a 12% increase in production and a slight increase in realized selling prices.

The Company's fourth quarter natural gas sales portfolio was approximately based on the following pre-existing physical contracts or market prices:

	Q4 2017
AECO physical delivery sales contracts	59%
AECO floating	—%
Dawn	22%
Chicago Citygate	19%

NuVista receives a premium to the AECO 5A 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 markets in North America outside Alberta to limit its exposure to AECO pricing. For the three months ended December 31, 2017, natural gas sales under AECO physical delivery sales contracts represented approximately 59% of the Company's total natural gas production. NuVista received Chicago Citygate pricing on approximately 19% of its natural gas production and Dawn pricing on approximately 22%. The Company has a contract in place for volumes to be sold to California (Malin) starting in 2018.

NuVista's exposure to AECO floating prices is limited to approximately 1% of forecast volumes in 2018 as a result of this price diversification, 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 months and year ended December 31, 2017 was $2.70/Mcf and $3.04/Mcf respectively, compared to $3.25/Mcf and $2.62/Mcf for the comparative periods of 2016, and $2.77/Mcf in the third quarter of 2017.

Condensate & oil revenue

For the three months ended December 31, 2017, condensate & oil revenue increased 112% over the comparable period of 2016, due to a 80% increase in production and a 17% increase in realized selling prices. For the year ended December 31, 2017, condensate & oil revenue increased 75% over the comparable period of 2016, due primarily to a 43% increase in production and a 22% increase in realized selling prices.

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 and oil prices realized selling prices averaged $68.36/Bbl and $61.01/Bbl in the three months and year ended December 31, 2017, an increase of 17% and 22% from $58.21/Bbl and $49.81/Bbl for the comparable periods of 2016, consistent with the increase in WTI prices compared to 2016.

NGL revenue

For the three months ended December 31, 2017, NGL revenue increased 183% over the comparable period of 2016, due to a 71% increase in production and a 66% increase in realized selling prices. For the year ended December 31, 2017, NGL revenue increased 181% over the comparable period of 2016, due primarily to a 20% increase in production and a 134% 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%

In addition, the Board of Directors has set limits for entering into natural gas basis differential contracts, subject to a maximum volume of up to 100,000 MMbtu/day and with a term of less than 7 years from the date any such swap is entered into, 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.

	Three months ended December 31					
($ thousands)	**2017**			2016		
	Realized gain (loss)	**Unrealized gain (loss)**	**Total gain (loss)**	Realized gain (loss)	Unrealized gain (loss)	Total gain (loss)
Natural gas	**1,311**	**29,950**	**31,261**	(343)	2,362	2,019
Condensate, oil and NGLs	**(743)**	**(23,952)**	**(24,695)**	2,656	(13,947)	(11,291)
Gain (loss) on financial derivatives	**568**	**5,998**	**6,566**	2,313	(11,585)	(9,272)

During the fourth quarter of 2017, the commodity price risk management program resulted in a total gain of $6.6 million, compared to a total loss of $9.3 million for the comparable period of 2016. 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.

	Year ended December 31					
($ thousands)	**2017**			2016		
	Realized gain (loss)	**Unrealized gain (loss)**	**Total gain (loss)**	Realized gain (loss)	Unrealized gain (loss)	Total gain (loss)
Natural gas	**3,963**	**31,659**	**35,622**	1,652	4,545	6,197
Condensate, oil and NGLs	**1,101**	**(35)**	**1,066**	24,677	(38,072)	(13,395)
Gain (loss) on financial derivatives	**5,064**	**31,624**	**36,688**	26,329	(33,527)	(7,198)

For the year ended December 31, 2017, the commodity price risk management program resulted in a gain of $36.7 million compared to a realized loss of $7.2 million for the comparable period of 2016.

Price risk management gains on our physical delivery sale contracts totaled $8.9 million and $21.4 million for the three months and year ended December 31, 2017 compared to gains of $4.3 million and $32.6 million for the comparable periods of 2016. The mark to market value of the physical delivery sale contracts at December 31, 2017 was an asset of $19.4 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 December 31, 2017:

	Volume (Bbls/d)	Pricing (Cdn$/Bbl)	Term of contract
WTI crude oil sales price derivatives			
Fixed price swap	5,500	$70.56	Jan 1, 2018 - Mar 31, 2018
Fixed price swap	6,100	$70.58	Apr 1, 2018 - Dec 31, 2018
Fixed price swap	1,600	$68.93	Jan 1, 2019 - Mar 31, 2019
Fixed price swap	1,000	$67.79	Apr 1, 2019 - Jun 30, 2019
Fixed price swap	500	$68.16	Jul 1, 2019 - Dec 31, 2019

	Volume (Bbls/d)	Pricing (US$/Bbl)	Term of contract
WTI crude oil sales price derivatives			
Fixed price swap	1,000	$50.24	Jan 1, 2018 - Dec 31, 2018

	Volume (MMbtu/d)	Pricing (US$/MMbtu)	Term of contract
NYMEX natural gas sales price derivatives			
AECO-NYMEX basis	10,000	($0.69)	Jan 1, 2018 - Sep 30, 2018
AECO-NYMEX basis	23,261	($0.65)	Oct 1, 2018 - Dec 31, 2018
AECO-NYMEX basis	42,500	($0.76)	Jan 1, 2019 - Mar 31, 2019
AECO-NYMEX basis	17,500	($0.94)	Apr 1, 2019 - Dec 31, 2019
AECO-NYMEX basis	47,500	($0.96)	Jan 1, 2020 - Dec 31, 2020
AECO-NYMEX basis	95,000	($0.98)	Jan 1, 2021 - Dec 31, 2021
AECO-NYMEX basis	95,000	($0.97)	Jan 1, 2022 - Dec 31, 2022
AECO-NYMEX basis	50,000	($0.98)	Jan 1, 2023 - Dec 31, 2023
AECO-NYMEX basis	50,000	($0.96)	Jan 1, 2024 - Dec 31, 2024
Chicago-NYMEX basis	10,000	($0.20)	Jan 1, 2018 - Sep 30, 2018
Chicago-NYMEX basis	3,370	($0.20)	Oct 1, 2018 - Dec 31, 2018
Malin-NYMEX Basis	10,000	($0.40)	Apr 1, 2018 - Sep 30, 2018
Malin-NYMEX Basis	16,630	($0.40)	Oct 1, 2018 - Dec 31, 2018
Malin-NYMEX Basis	20,000	($0.40)	Jan 1, 2019 - Sep 30, 2019
Malin-NYMEX Basis	13,370	($0.42)	Oct 1, 2019 - Dec 31, 2019
Malin-NYMEX Basis	10,000	($0.45)	Jan 1, 2020 - Sep 30, 2020
Malin-NYMEX Basis	3,370	($0.45)	Oct 1, 2020 - Dec 31, 2020
NYMEX fixed price swap	43,278	$3.03	Jan 1, 2018 - Mar 31, 2018
NYMEX fixed price swap	45,000	$3.02	Apr 1, 2018 - Sep 30, 2018
NYMEX fixed price swap	35,054	$2.96	Oct 1, 2018 - Dec 31, 2018
NYMEX fixed price swap	10,000	$2.78	Jan 1, 2019 - Sep 30, 2019
NYMEX fixed price swap	3,370	$2.78	Oct 1, 2019 - Dec 31, 2019

Subsequent to December 31, 2017 the following is a summary of financial derivatives that have been entered into:

	Volume (Bbls/d)	Pricing (Cdn$/Bbl)	Term of contract
WTI crude oil sales price derivatives			
Fixed price swap	600	$73.17	Jul 1, 2018 - Sep 30, 2018
Fixed price swap	800	$73.10	Oct 1, 2018 - Dec 31, 2018
Fixed price swap	1,300	$72.48	Jan 1, 2019 - Jun 30, 2019
Fixed price swap	700	$71.89	Jul 1, 2019 - Sep 30, 2019
Fixed price swap	500	$71.48	Oct 1, 2019 - Dec 31, 2019

	Volume (MMbtu/d)	Pricing (US$/MMbtu)	Term of contract
NYMEX natural gas sales price derivatives			
Dawn-NYMEX basis	15,000	($0.22)	Apr 1, 2018 - Sep 30, 2018
Dawn-NYMEX basis	5,054	($0.22)	Oct 1, 2018 - Dec 31, 2018
Chicago-NYMEX basis	6,630	($0.26)	Oct 1, 2018 - Dec 31, 2018
Chicago-NYMEX basis	10,000	($0.26)	Jan 1, 2019 - Sep 30, 2019
Chicago-NYMEX basis	13,315	($0.25)	Oct 1, 2019 - Dec 31, 2019
Chicago-NYMEX basis	15,000	($0.25)	Jan 1, 2020 - Dec 31, 2020
Chicago-NYMEX basis	15,000	($0.24)	Jan 1, 2021 - Sep 30, 2022
Chicago-NYMEX basis	5,054	($0.24)	Oct 1, 2022 - Dec 31, 2022
AECO-NYMEX basis	50,000	($1.03)	Jan 1, 2023 - Dec 31, 2024
NYMEX fixed price swap	13,261	$2.79	Oct 1, 2018 - Dec 31, 2018
NYMEX fixed price swap	20,000	$2.79	Jan 1, 2019 - Sep 30, 2019
NYMEX fixed price swap	6,739	$2.79	Oct 1, 2019 - Dec 31, 2019

(b) Physical delivery sales contracts

The following is a summary of the physical delivery sales contracts in place as at December 31, 2017:

	Volume (GJ/d)	Pricing (Cdn$/GJ)	Term of contract
Natural gas physical delivery sales contracts			
AECO fixed price swap	47,500	$2.72	Jan 1, 2018 - Sep 30, 2018
AECO fixed price swap	29,266	$2.72	Oct 1, 2018 - Dec 31, 2018

Subsequent to December 31, 2017 the following is a summary of physical delivery sales contracts that have been entered into:

	Volume (GJ/d)	Pricing (Cdn$/GJ)	Term of contract
Natural gas physical delivery sales contracts			
Dawn fixed price swap	3,444	$3.07	Jan 1, 2018 - Mar 31, 2018
Dawn fixed price swap	10,000	$3.07	Apr 1, 2018 - Sep 30, 2018
Dawn fixed price swap	3,370	$3.07	Oct 1, 2018 - Dec 31, 2018

Royalties

($ thousands, except % and per Boe amounts)	Three months ended December 31 2017	2016	Year ended December 31 2017	2016
Gross royalties	**7,062**	3,913	**20,281**	13,720
Gas cost allowance ("GCA")	**(2,293)**	(2,960)	**(8,132)**	(11,859)
Net royalties	**4,769**	953	**12,149**	1,861
Gross royalty % excluding physical delivery sales contracts(1)	**5.8**	5.6	**5.7**	6.1
Gross royalty % including physical delivery sales contracts	**5.4**	5.2	**5.4**	5.3
Net royalties per Boe	**1.38**	0.42	**1.12**	0.21

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

For the three months and year ended December 31, 2017, gross royalties excluding GCA credits were $7.1 million and $20.3 million respectively, compared to $3.9 million and $13.7 million for the comparable periods of 2016. The increase in gross royalty dollars is due primarily to increased production and higher realized selling prices. The gross royalty rate excluding physical delivery sales contracts remained consistent around 6% for both years, as the majority of total corporate production is from Montney which qualifies for reduced royalties during the initial capital payback period of the wells.

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 year ended December 31, 2017, the 31% decrease in GCA credits received compared to the comparative period of 2016 is primarily due to temporarily higher GCA credits received in 2016 related to the recent construction of Company owned compressor stations.

NuVista’s physical price risk management activities impact reported 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

($ thousands, except per Boe amounts)	Three months ended December 31 2017	2016	Year ended December 31 2017	2016
Transportation expense	**8,858**	4,869	**28,951**	21,119
Per Boe	**2.57**	2.14	**2.66**	2.34

For the three months and year ended December 31, 2017, transportation expenses on a total dollar and per Boe basis increased from the comparative periods of 2016 due to higher volumes, and additional firm commitments for gas transportation. NuVista incurs higher transportation expenses on these volumes, however, the tolls are 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 third quarter transportation expense of $6.8 million ($2.51/Boe), transportation expenses for the fourth quarter increased as a result of increased production and additional Dawn LTFP firm service that came into effect in November 2017.

Operating expenses

	Three months ended December 31		Year ended December 31	
($ thousands, except per Boe amounts)	**2017**	2016	**2017**	2016
Operating expenses	**33,247**	23,742	**111,465**	94,821
Per Boe	**9.65**	10.44	**10.25**	10.52

For the three months and year ended December 31, 2017, operating expenses per Boe decreased 8% and 3% respectively from the comparative periods of 2016, due to increased production and operational efficiencies, increased utilization of the Elmworth and Bilbo compressor stations. Compared to third quarter operating expenses of $27.7 million ($10.26/Boe), fourth quarter operating expenses per Boe decreased as a result of higher production volumes from new wells and increased run time following the scheduled third party facility outage that occurred in the third quarter.

General and administrative expenses ("G&A")

	Three months ended December 31		Year ended December 31	
($ thousands, except per Boe amounts)	**2017**	2016	**2017**	2016
Gross G&A expenses	**6,372**	5,147	**22,567**	22,436
Overhead recoveries	**(47)**	(68)	**(453)**	(427)
Capitalized G&A	**(1,189)**	(1,018)	**(4,737)**	(5,380)
Net G&A expenses	**5,136**	4,061	**17,377**	16,629
Gross G&A per Boe	**1.85**	2.26	**2.08**	2.49
Net G&A per Boe	**1.49**	1.79	**1.60**	1.84

As a result of continued focus on Wapiti Montney and disposition of non core properties, NuVista has continued to realize efficiencies, and gross G&A expenses have remained consistent on an annual basis despite growing production. On a per Boe basis, G&A expenses have decreased in both periods primarily 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 2016 and 2017. G&A capitalized and operating recoveries are in accordance with industry practice.

Share-based compensation expense

	Three months ended December 31		Year ended December 31	
($ thousands)	**2017**	2016	**2017**	2016
Stock options	**966**	721	**3,387**	2,651
Restricted stock units	**—**	—	**—**	499
Director deferred share units	**487**	317	**1,038**	751
Restricted share awards	**440**	326	**1,544**	1,183
Total	**1,893**	1,364	**5,969**	5,084

Share-based compensation expense relates to the amortization of the fair value of stock option awards and restricted share awards ("RSA") and accruals for future payments under the restricted stock unit ("RSU") plan and director deferred share unit ("DSU") plan. The DSU plan was approved by shareholders at NuVista's annual and special meeting in May 2016. The increase in share-based compensation for the three months and year ended December 31, 2017 compared to the comparable periods of 2016 is due to the increase in the weighted average fair value of stock options granted in 2017 and the appreciation of the Company's share price compared to 2016.

During the second quarter of 2016, all outstanding RSUs became fully vested and the Company has not granted any further RSUs.

Financing costs

	Three months ended December 31		Year ended December 31	
($ thousands, except per Boe amounts)	**2017**	2016	**2017**	2016
Interest on long-term debt (credit facility)	**1,274**	351	**4,364**	6,161
Interest on senior unsecured notes	**1,875**	1,861	**7,436**	3,899
Interest expense	**3,149**	2,212	**11,800**	10,060
Accretion expense	**387**	365	**1,524**	1,771
Total financing costs	**3,536**	2,577	**13,324**	11,831
Interest expense per Boe	**0.91**	0.97	**1.09**	1.12
Total financing costs per Boe	**1.03**	1.13	**1.23**	1.31

Interest expense on long-term debt includes interest expenses on bank debt and standby charges on the Corporation's syndicated credit facilities. For the three months ended December 31, 2017 interest expense on long-term debt increased 263% from the comparable period in 2016 due to additional bank debt throughout the period, as well as larger available syndicated credit facilities on which standby fees are calculated. For the year ended December 31, 2017, interest on long-term debt decreased 29% from the comparable period in 2016 due to lower average debt levels throughout the period. Average borrowing costs on long term debt for the three months and year ended December 31, 2017 were 3.2% and 3.0% compared to average borrowing costs of 3.0% and 3.2% for the comparative periods of 2016.

Interest on the $70.0 million senior unsecured notes issued June 22, 2016, for the three months and year ended December 31, 2017, is for the quarterly interest installment and accrued interest to the end of the period. Interest is accrued on the carrying value at the effective interest rate of 11.0%. The carrying value of senior unsecured notes at December 31, 2017 was $67.7 million.

Accretion expense on asset retirement obligations decreased for the three months and year ended December 31, 2017 compared to the comparative periods of 2016, as a result of the decrease to the liability balance at December 31, 2017.

Adjusted funds flow

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

	Three months ended December 31		Year ended December 31	
($ thousands)	**2017**	2016	**2017**	2016
Cash provided by operating activities	**109,078**	52,724	**224,680**	126,751
Add back:				
Environmental remediation recovery	**—**	—	**(2,550)**	—
Asset retirement expenditures	**1,944**	3,185	**9,813**	10,791
Note receivable recovery	**—**	—	**—**	(350)
Change in non-cash working capital	**(35,090)**	(15,212)	**(31,913)**	649
Adjusted funds flow(1)	**75,932**	40,697	**200,030**	137,841

(1) Refer to “Non-GAAP measurements”.

The tables below summarize operating netbacks for the three months ended December 31, 2017 and 2016:

	Three months ended December 31, 2017		Three months ended December 31, 2016	
($ thousands, except per Boe amounts)	**$**	**$/Boe**	$	$/Boe
Petroleum and natural gas revenues [(1)]	**131,009**	**38.04**	74,538	32.78
Realized gain on financial derivatives	**568**	**0.16**	2,313	1.02
	131,577	**38.20**	76,851	33.80
Royalties	**(4,769)**	**(1.38)**	(953)	(0.42)
Transportation expenses	**(8,858)**	**(2.57)**	(4,869)	(2.14)
Operating expenses	**(33,247)**	**(9.65)**	(23,742)	(10.44)
Operating netback[(2)]	**84,703**	**24.60**	47,287	20.80
General and administrative	**(5,136)**	**(1.49)**	(4,061)	(1.79)
Restricted stock units & deferred share units	**(486)**	**(0.14)**	(317)	(0.14)
Interest expense	**(3,149)**	**(0.91)**	(2,212)	(0.97)
Adjusted funds flow netback[(2)]	**75,932**	**22.06**	40,697	17.90

[(1)] Includes price risk management gains of $8.9 million (2016 - $4.3 million gain) on physical delivery sales contracts.
[(2)] Refer to "Non-GAAP measurements".

For the three months ended December 31, 2017, NuVista's adjusted funds flow were $75.9 million ($0.44/share, basic), compared to $40.7 million ($0.24/share, basic) for the comparable period of 2016 and $41.5 million ($0.24/share, basic) in the third quarter of 2017. The increased adjusted funds flow in the fourth quarter of 2017 compared to the fourth quarter of 2016 is primarily a result of higher realized commodity pricing and higher production, partially offset by lower realized gains from the commodity price risk management program.

The tables below summarize operating netbacks for the year ended December 31, 2017 and 2016:

	Year ended December 31, 2017		Year ended December 31, 2016	
($ thousands, except per Boe amounts)	**$**	**$/Boe**	$	$/Boe
Petroleum and natural gas revenues [(1)]	**377,746**	**34.75**	257,252	28.53
Realized gain on financial derivatives	**5,064**	**0.47**	26,329	2.92
	382,810	**35.22**	283,581	31.45
Royalties	**(12,149)**	**(1.12)**	(1,861)	(0.21)
Transportation expenses	**(28,951)**	**(2.66)**	(21,119)	(2.34)
Operating expenses	**(111,465)**	**(10.25)**	(94,821)	(10.52)
Operating netback[(2)]	**230,245**	**21.19**	165,780	18.38
General and administrative	**(17,377)**	**(1.60)**	(16,629)	(1.84)
Restricted stock units & deferred share units	**(1,038)**	**(0.10)**	(1,250)	(0.14)
Interest expense	**(11,800)**	**(1.09)**	(10,060)	(1.12)
Adjusted funds flow netback[(2)]	**200,030**	**18.40**	137,841	15.28

[(1)] Includes price risk management gains of $21.4 million (2016 - $32.6 million gain) on physical delivery sales contracts.
[(2)] Refer to "Non-GAAP measurements".

For the year ended December 31, 2017, adjusted funds flow was $200.0 million ($1.15/share, basic) compared to $137.8 million ($0.87/share, basic) for the comparable period of 2016. Adjusted funds flow was higher than the comparable period of 2016 primarily due to higher production levels and realized commodity pricing, offset by lower realized gains and higher royalties, transportation and operating expenses.

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. It is anticipated that the majority of the remaining remediation will occur through 2018. 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.

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 December 31		Year ended December 31	
($ thousands, except per Boe amounts)	**2017**	2016	**2017**	2016
Depletion of oil and gas assets	**48,262**	22,102	**121,913**	84,321
Depreciation of fixed assets	**3,671**	3,339	**13,675**	14,562
DD&A expense	**51,933**	25,441	**135,588**	98,883
Exploration and evaluation ("E&E") impairment expense	**1,427**	2,089	**1,427**	2,089
Total DD&A and impairment expense	**53,360**	27,530	**137,015**	100,972
DD&A rate per Boe	**15.08**	11.19	**12.47**	10.97

DD&A expense for three months and year ended December 31, 2017 was $51.9 million ($15.08/Boe) and $135.6 million ($12.47/Boe) respectively, compared to $25.4 million ($11.19/Boe) and $98.9 million ($10.97/Boe) for the comparable periods of 2016, and $29.7 million ($10.98/Boe) in the third quarter of 2017.

For the three months and year ended December 31, 2017, DD&A expense increased on a total dollar and per Boe basis compared to the comparable periods of 2016 and the third quarter of 2017. Substantially all of the net book value of PP&E for the CGUs excluding Wapiti Montney was depleted at year end as a result of minimal reserves assigned to those CGUs in the year end reserve report. The amount of DD&A expense on these non core CGUs was $18.2 million, resulting in an increase in the DD&A rate for the year ended December 31, 2017 to be $12.47/Boe compared to $10.97/Boe in the comparable period of 2016.

The Wapiti Montney DD&A rate per Boe for three months and year ended December 31, 2017 decreased to $9.87/Boe and $10.55/Boe compared to $10.82/Boe and $11.21/Boe for the comparable periods of 2016, and $10.63/Boe in the third quarter of 2017. This decrease is a result of improved year end reserves.

During the year ended December 31, 2017, there were no indicators of impairment or reversal of impairment identified on any of the Company's CGU's within property, plant & equipment.

At December 31, 2017, there were indicators of impairment for exploration & evaluation assets ("E&E") in NuVista's non core CGUs that the carrying amount of E&E is not likely to be recovered and an impairment test was performed on these E&E assets. The impairment test resulted in an impairment charge totaling $1.4 million in the Shallow Gas, Deep Gas, and North Gas CGUs. This charge has been included in depletion, depreciation, amortization and impairment expense. At December 31, 2017, there were no indicators of impairment in the Wapiti Montney CGU. The remaining net book value of E&E at December 31, 2017 is all attributed to the Wapiti Montney CGU.

Exploration and evaluation ("E&E") expense

	Three months ended December 31		Year ended December 31	
($ thousands, except per Boe amounts)	**2017**	2016	**2017**	2016
Exploration and evaluation expense	**6,888**	459	**6,932**	827
Per Boe	**2.00**	0.20	**0.64**	0.09

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

Asset retirement obligations

($ thousands)	**2017**	2016
Balance, January 1	**75,463**	101,818
Accretion expense	**1,524**	1,771
Liabilities incurred	**3,698**	2,332
Liabilities disposed	**(3,272)**	(13,753)
Change in estimates and discount rate	**4,830**	(5,914)
Liabilities settled	**(9,813)**	(10,791)
Balance, end of period	**72,430**	75,463
Expected to be incurred within one year	**14,250**	8,800
Expected to be incurred beyond one year	**58,180**	66,663

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 December 31, 2017, NuVista had an ARO balance of $72.4 million as compared to $75.5 million as at December 31, 2016. The liability was discounted using a risk free discount rate of 2.4% at December 31, 2017 (December 31, 2016 – 2.3%). At December 31, 2017, the estimated total undiscounted amount of cash flow required to settle NuVista’s ARO was $75.9 million (December 31, 2016 – $71.3 million). The majority of the costs are expected to be incurred between 2018 and 2037. The decrease in ARO in the year ended December 31, 2017 is primarily a result of NuVista's ongoing abandonment program and liabilities disposed. Actual ARO expenditures for the three months and year ended December 31, 2017 were $0.9 million and $9.8 million respectively, compared to $3.2 million and $10.8 million for the comparable periods of 2016.

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 December 31		Year ended December 31	
($ thousands)	**2017**	2016	**2017**	2016
Exploration and evaluation assets and property plant and equipment (1)				
Land and retention costs	**(493)**	73	**510**	718
Geological and geophysical	**1,303**	835	**5,201**	5,377
Drilling and completion	**30,677**	43,107	**246,727**	141,665
Facilities and equipment	**7,801**	11,583	**61,350**	41,074
Corporate and other	**811**	187	**1,514**	227
Total capital expenditures	**40,099**	55,785	**315,302**	189,061

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

Capital expenditures for the three months ended December 31, 2017 were lower than the comparative period in 2016 due to fewer wells drilled in the quarter compared to the prior year, in addition to realizing continued reductions in drilling and completion costs as a result of efficiencies gained from multi-well pad drilling. The Company focused 77% of its capital expenditures on drilling and completion activities, with 19% on facilities and equipment, primarily related to bringing wells on production and adding additional compression.

Capital expenditures for the year ended December 31, 2017 are higher than the comparable period of 2016, consistent with higher budgeted capital activity. During 2017, the Company drilled 10 more wells, completed 14 more wells, and brought 9 more wells onto production in the year in comparison to 2016, with substantially all capital expenditures in both years spent on liquids-rich natural gas projects in our Wapiti Montney core area. Of the $315.3 million capital spent in 2017, $314.5 million was spent on property, plant and equipment expenditures, and $0.8 million was spent on exploration and evaluation expenditures.

Acquisitions and dispositions

For the year ended December 31, 2017, total proceeds from non core property dispositions were $2.2 million, resulting in a loss on dispositions of $6.8 million, as compared to proceeds of $76.0 million in the comparable period of 2016, resulting in a loss of $0.5 million, primarily from the sale of assets in the Wapiti Sweet operating area in the second quarter of 2016.

Deferred income taxes

For the year ended December 31, 2017, the provision for income taxes was a benefit of $17.4 million, compared to a benefit of $1.6 million in the comparable period of 2016. At December 31, 2017, the Company recognized the full benefit of the Company's tax pool balances exceeding accounting carrying values. 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. At December 31, 2016, a full valuation allowance was taken against the deferred tax asset.

Tax pools

At December 31, 2017, NuVista had approximately $1.1 billion (2016 – $923.0 million) of estimated tax pools available for deduction against future years' taxable income. The Company does not forecast to be cash taxable in the current 5 year plan.

($ thousands)	Available tax pools 2017	Maximum annual deduction %
Canadian exploration expense	**239,000**	100%
Canadian development expense	**352,000**	30% declining balance
Canadian oil and natural gas property expense	**63,000**	10% declining balance
Undepreciated capital cost	**202,000**	25% declining balance
Non-capital losses	**231,000**	100%
Other	**5,000**	various rates
Total federal tax pools	**1,092,000**	
Additional Alberta tax pools	**13,000**	100%

Net earnings (loss)

	Three months ended December 31		Year ended December 31	
($ thousands, except per share amounts)	**2017**	2016	**2017**	2016
Net earnings (loss)	**34,651**	1,135	**94,368**	(1,653)
Per share - basic	**0.20**	0.01	**0.54**	(0.01)
Per share - diluted	**0.20**	0.01	**0.54**	(0.01)

The increase in net earnings for the three months and year ended December 31, 2017 compared to the prior year comparative periods is primarily a result of the increased adjusted funds flow, increased unrealized hedging gains and an increase in the deferred income tax benefit.

Liquidity and capital resources

Long-term debt (credit facility)

At December 31, 2017, the Company had a $310.0 million (December 31, 2016 - $200 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 December 31, 2017, NuVista was in compliance with all covenants.

The semi annual review was completed in the fourth quarter with an increase to the credit facility to $310 million. The next annual review is scheduled for on or before April 30, 2018.

Senior unsecured notes

On June 22, 2016, the Company issued $70 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.

The 2021 Notes are non callable by the Company prior to the two and a half year anniversary of the issuance date. At any time on or after December 22, 2018, the Company may redeem all or part of the 2021 Notes at the redemption prices set forth in the table below plus any accrued and unpaid interest:

12 month period ended:	Percentage
December 22, 2019	104.938%
December 22, 2020	102.469%
December 22, 2021	100.000%

If a change of control occurs, each holder of 2021 Notes will have the right to require the Company to purchase all or any part of that holder's 2021 Notes for an amount in cash equal to 101% of the aggregate principal repurchased plus accrued and unpaid interest.

Subsequent event

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"). 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.

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 plus an agreed redemption premium of $6.6 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)	**December 31, 2017**	December 31, 2016
Common shares outstanding	**174,004**	172,746
Share price(1)	**8.02**	6.94
Total market capitalization	**1,395,512**	1,198,857
Adjusted working capital deficit(2)	**2,784**	15,536
Senior unsecured notes	**67,680**	67,156
Long-term debt (credit facility)	**125,725**	—
Net debt (2)	**196,189**	82,692
Annualized current quarter adjusted funds flow(2)	**303,728**	162,788
Net debt to annualized current quarter adjusted funds flow(2)	**0.6**	0.5

(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 December 31, 2017, net debt was $196.2 million, resulting in a net debt to annualized current quarter adjusted funds flow ratio of 0.6x. 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 December 31, 2017, NuVista had an adjusted working capital deficit of $2.8 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 December 31, 2017, NuVista had drawn $125.7 million on its long-term debt (credit facility) and had outstanding letters of credit of $13.2 million which reduce the credit available on the credit facility, leaving $171.1 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 to $310 million in the context of commodity prices and net debt levels. NuVista plans to finance its 2018 capital program with adjusted funds flow, and proceeds from a senior unsecured note issuance, and the credit facility.

As at December 31, 2017, there were 174.0 million common shares outstanding. In addition, there were 6.5 million stock options with an average exercise price of $7.43 per option and 0.6 million RSAs 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 December 31, 2017:

($ thousands)	**Total**	2018	2019	2020	2021	2022	Thereafter
Transportation and processing (1)	**988,645**	83,178	86,900	95,513	107,707	107,437	507,910
Office lease	**14,627**	1,814	1,814	1,826	1,887	1,893	5,393
Total commitments	**1,003,272**	84,992	88,714	97,339	109,594	109,330	513,303

(1) Certain of the transportation and processing commitments are secured by outstanding letters of credit of $12.8 million at December 31, 2017 (December 31, 2016 - $16.5 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.

Annual financial information

The following table highlights selected annual financial information for the years ended December 31, 2017, 2016 and 2015:

($ thousands, except per share amounts)	**2017**	2016	2015
Petroleum and natural gas revenues	**377,746**	257,252	225,685
Net earnings (loss)	**94,368**	(1,653)	(172,925)
Per basic and diluted share	**0.54**	(0.01)	(1.16)
Balance sheet information			
Total assets	**1,186,419**	961,240	981,637
Long-term debt	**125,725**	—	196,733
Shareholders' equity	**863,579**	756,029	629,639

Quarterly financial information

The following table highlights NuVista's performance for the eight quarterly reporting periods from March 31, 2016 to December 31, 2017:

($ thousands, except	**2017**				2016			
per share amounts)	**Dec 31**	Sep 30	Jun 30	Mar 31	Dec 31	Sep 30	Jun 30	Mar 31
Production (Boe/d)	**37,435**	29,405	25,454	26,731	24,716	24,898	23,451	25,484
Petroleum and natural gas revenues	**131,009**	83,100	79,401	84,236	74,538	65,155	57,840	59,720
Net earnings (loss)	**34,651**	(4,366)	25,767	38,317	1,135	2,079	(7,320)	2,453
Net earnings (loss)								
Per basic and diluted share	**0.20**	(0.03)	0.15	0.22	0.01	0.01	(0.05)	0.02
Adjusted funds flow	**75,932**	41,526	39,318	43,254	40,697	31,237	35,619	30,288
Per basic and diluted share	**0.44**	0.24	0.23	0.25	0.24	0.20	0.23	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. Total Company production increases have more than offset production from non core property dispositions. Over the prior eight quarters, quarterly revenue has been in a range of $57.8 million to $131.0 million with revenue primarily influenced by production volumes and commodity prices. Net earnings (losses) have been in a range of a net loss of $7.3 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

Future accounting changes

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 NuVista on January 1, 2018. The Company has substantially completed its review of various revenue streams and underlying contracts with customers. It has been concluded that the adoption of IFRS 15 will not have a material impact on NuVista's net income and financial position. NuVista will provide enhanced disclosures in the notes to its financial statements beginning in Q1 2018, including disclosing the Company's disaggregated revenue streams by product type.

In July 2014, the IASB issued IFRS 9, “Financial Instruments” to replace IAS 39, “Financial Instruments: Recognition and Measurement”. The standard supersedes earlier versions of IFRS 9 and completes the IASB’s project to replace *IAS 39 Financial Instruments: Recognition and Measurement*. IFRS 9 introduces a single approach to determine whether a financial asset is measured at amortized cost or fair value and replaces the multiple rules in IAS 39. The approach is based on how an entity manages its financial instruments in the context of its business model and the contractual cash flow characteristics of the financial assets. For financial liabilities, IFRS 9 retains most of the requirements of IAS 39; however, 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 in OCI rather than the statement of income, unless this creates an accounting mismatch. IFRS 9 also contains a new model to be used for hedge accounting. The Company does not currently apply hedge accounting to its risk management contracts and does not currently intend to apply hedge accounting to any of its existing risk management contracts on adoption of IFRS 9. The standard will come into effect for annual periods beginning on or after January 1, 2018, with earlier adoption permitted. IFRS 9 will be applied on a retrospective basis by NuVista on January 1, 2018. The Company has determined that adoption of IFRS 9 will result in changes to the classification of the Company's financial assets, but will not change the classification of the Company's financial liabilities. The Company has also determined there will not be any material changes in the measurement and carrying value of the Company's financial instruments as a result of the adoption of IFRS 9.

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 evaluating the impact of the standard may have on the financial statements, as well as the impact that adoption of the standard will have on disclosure.

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 expects the Climate Leadership Plan to increase the cost of operating its properties and is currently evaluating the expected impact of this plan on its results of operations.

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 will be contained in our Annual Information Form under the Industry Conditions section for the year ended December 31, 2017, which will be filed on SEDAR on or before March 30, 2018.

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 year ended December 31, 2017, 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;
- 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 will be contained in our Annual Information Form under the Risk Factors Section for the year ended December 31, 2017, which will be filed on SEDAR on or before March 30, 2018.

2018 Guidance:

Guidance for 2018 remains as previously announced with capital spending anticipated in the range of $270 - $310 million and 2018 production expected in the range of 35,000 - 40,000 Boe/d. Production for the first quarter of 2018 is anticipated to be in the range of 34,500 - 36,000 Boe/d. Full year adjusted funds flow is anticipated to be in the range of $200 - $230 million after adjusting for the non-recurring cost of refinancing the senior unsecured notes in the first quarter of 2018. This is based on our 2018 forecast production and assumed commodity prices of US$3.00/MMBtu NYMEX and US$55/Bbl WTI. The resulting 2018 net debt to adjusted funds flow ratio is expected to be approximately 1.3 times. In estimating the figures above we have assumed that our production and condensate ratio moderate slightly as compared to the fourth quarter of 2017, after flush production subsides somewhat from new wells brought onstream in that quarter.