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, 2018. The following MD&A of financial condition and results of operations was prepared at and is dated March 5, 2019. Our December 31, 2018 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 29, 2019.

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; the effect of financial, commodity, and natural gas risk management strategy and market diversification; NuVista's planned capital expenditures and sources of funding; drilling plans; expectations with respect t the construction and start up of the Pipestone compressor station; planned 2019 maintenance outages; funding plans with respect to the Pipestone compressor station; NuVista's 110,000 Boe/d growth plan; the anticipated potential and growth opportunities associated with NuVista's asset base; NuVista's future exposure to AECO; the impact of royalty changes on NuVista's results of operations; capital spending, production and adjusted funds flow guidance; 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 future development opportunities associated with the Pipestone Acquisition; estimated tax pools and future taxability; 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.*

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", "operating netback", "corporate netback", "capital expenditures" and "net debt" to analyze performance and leverage. These terms do not have any standardized meaning prescribed by IFRS and therefore may not be comparable to similar measures presented by other companies where similar terminology is used. For further information refer to the section "Non-GAAP measures" within this MD&A.

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.

Asset Transactions

On September 6, 2018, the Company closed the acquisition of Cenovus Pipestone ULC and Cenovus Pipestone Partnership (the "Pipestone Acquisition") which held assets in the Pipestone area of Northwest Alberta (the "Acquired Assets") for $619.4 million including customary adjustments. Subsequently, all of the Acquired Assets were assumed by NuVista and the partnership and ULC were dissolved. The Acquired Assets are situated primarily in the condensate-rich Alberta Triassic Montney fairway on 35,250 net acres of land featuring four layers of Montney development, and represented a 29% increase to the Company's Montney land position, adding approximately 9,600 Boe/d per year of production and significant infrastructure. The Pipestone Acquisition was funded with the Company's expanded credit facilities and the issuance of 47.4 million common shares at a price of $8.10 per share for gross proceeds of $384.1 million.

There were no property dispositions in the three months and year ended December 31, 2018, compared to minor dispositions of non core assets in the comparable periods of 2017.

Drilling activity

	Three months ended December 31		Year ended December 31	
Number of wells	**2018**	2017	**2018**	2017
Wells drilled - gross (net) (1)	**3.0 (3.0)**	4.0 (4.0)	**26.0 (25.5)**	30.0 (30.0)
Wells completed - gross (net) (2)	**5.0 (4.8)**	3.0 (3.0)	**23.0 (22.5)**	32.0 (32.0)
Wells brought on production - gross (net) (3)	**0 (0.0)**	2.0 (2.0)	**19.0 (18.8)**	30.0 (30.0)

(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, 2018, NuVista drilled 3 (3.0 net) natural gas wells compared to 4 (4.0 net) natural gas wells in the comparable period of 2017. For the year ended December 31 2018, NuVista drilled 25 (24.5 net) natural gas wells and 1 disposal well, compared to 30 (30.0 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 98% and 100% respectively.

Production

	Three months ended December 31			Year ended December 31		
	2018	2017	% Change	**2018**	2017	% Change
Natural gas (Mcf/d)	**174,286**	131,703	32	**144,750**	108,187	34
Condensate & oil (Bbls/d)	**14,766**	13,087	13	**12,674**	9,860	29
Natural gas liquids ("NGLs") (Bbls/d)	**5,246**	2,397	119	**3,554**	1,893	88
Total (Boe/d)	**49,060**	37,435	31	**40,353**	29,783	35
Condensate, oil & NGLs weighting (1) (2)	**41%**	41%		**40%**	39%	
Condensate & oil weighting (2)	**30%**	35%		**31%**	33%	

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

Production for the three months and year ended December 31, 2018 increased 31% and 35% respectively over the comparative periods of 2017 as a result of production increases from new development in Montney and the incremental production associated with the Pipestone Acquisition. Fourth quarter production of 49,060 Boe increased significantly from third quarter 2018 production of 40,080 Boe/d, primarily as a result of full quarter production of the Acquired Assets. Condensate & oil volume weighting of 30% remained relatively steady compared to the prior year comparative periods, and 32%% in the third quarter of 2018.

Production from the Acquired Assets for the three months and year ended December 31, 2018 was 9,794 Boe/d and 3,214 Boe/d respectively, with the smaller annual production impact as a result of acquiring the assets on September 6, 2018.

Pricing

	Three months ended December 31			Year ended December 31		
	2018	2017	% change	**2018**	2017	% change
Realized selling prices [(1) & (2)]						
Natural gas ($/Mcf)	**3.69**	3.41	8	**3.51**	3.55	(1)
Condensate & oil ($/Bbl)	**51.60**	68.36	(25)	**70.92**	61.01	16
NGLs ($/Bbl)	**28.53**	33.17	(14)	**32.83**	25.81	27
Barrel of oil equivalent ($/Boe)	**31.69**	38.04	(17)	**37.74**	34.75	9
Benchmark pricing						
Natural gas - AECO 5A daily index (Cdn$/Mcf)	**1.56**	1.69	(8)	**1.50**	2.16	(31)
Natural gas - AECO 7A monthly index (Cdn$/Mcf)	**1.90**	1.96	(3)	**1.53**	2.43	(37)
Natural gas - NYMEX (monthly) (US$/MMbtu)	**3.64**	2.93	24	**3.09**	3.11	(1)
Natural gas - Chicago Citygate (monthly) (US$/MMbtu)	**3.62**	2.92	24	**3.06**	3.04	1
Natural gas - Dawn (daily) (US$/MMbtu)	**3.79**	2.95	28	**3.13**	3.04	3
Natural gas - Malin (monthly) (US$/MMbtu)	**3.90**	2.70	44	**2.69**	2.82	(5)
Oil - WTI (US$/Bbl)	**58.81**	55.40	6	**64.77**	50.95	27
Oil - Edmonton Par - (Cdn$/Bbl)	**42.79**	69.07	(38)	**69.39**	62.88	10
Condensate - Condensate @ Edmonton (Cdn$/Bbl)	**59.63**	73.74	(19)	**78.89**	66.90	18
Exchange rate - (Cdn$/US$)	**1.32**	1.27	4	**1.30**	1.30	—

(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 were 27% stronger on average in 2018 compared to 2017, however they declined in the fourth quarter with the WTI benchmark decreasing close to 15% from $69.50 in the third quarter of 2018 to average US $58.81/Bbl in the fourth quarter of 2018. US production growth continued its upward trajectory and production waivers given to Iran allowed for more supply than anticipated. This led to storage builds in the fourth quarter of 2018 and a softening of global oil prices. In December, OPEC and other nations agreed to a 1.2 million Bbl/d production cut to stabilize the global oil market. Canadian heavy oil differentials widened in a sudden and unprecedented fashion in the fourth quarter and this temporarily but significantly pressured the light oil market and also the condensate market. In December, the Alberta Government announced a mandated temporary oil supply curtailment which had the immediate effect of improving heavy oil, light oil and condensate differentials starting in January 2019. Condensate prices continued to outperform light oil prices with the Edmonton marker averaging C$59.63/Bbl for the quarter.

There has been sizable growth in US gas production in 2018 primarily from the Marcellus play along with associated gas from liquids production. This production growth was offset by growth in US liquid natural gas ("LNG") exports, exports to Mexico, and strong power demand. The significant storage deficit continued throughout the summer and into the winter heating season. NYMEX gas prices were up slightly compared to the third quarter of 2018 averaging US$3.64/MMbtu. Eastern North American and MidWest prices were similar to NYMEX gas prices in the fourth quarter. Gas production growth in Western Canada along with a slow start to winter led to continued weak AECO gas prices. AECO gas prices averaged $1.90/Mcf in the fourth quarter of 2018 representing an increase of 41% from $1.35/Mcf in the third quarter of 2018 but a 3% decrease from the fourth quarter of 2017.

Revenue

Petroleum and natural gas revenues

	Three months ended December 31				Year ended December 31			
	2018		2017		**2018**		2017	
($ thousands, except % amounts)	**$**	**% of total**	$	% of total	**$**	**% of total**	$	% of total
Natural gas [(1)]	**59,136**	**41**	41,395	32	**185,170**	**33**	140,350	37
Condensate & oil	**70,103**	**49**	82,299	63	**328,083**	**59**	219,561	58
NGLs [(2)]	**13,767**	**10**	7,315	5	**42,596**	**8**	17,835	5
Total petroleum and natural gas revenues	**143,006**		131,009		**555,849**		377,746	

(1) Natural gas revenue includes price risk management gains and losses on physical delivery sale contracts. For the three months and year ended December 31, 2018, our physical delivery sales contracts resulted in gains of $1.1 million and $18.3 million respectively (2017 – $8.9 million gain and $21.4 million gain).
(2) Includes butane, propane, and ethane and an immaterial amount of sulphur revenue.

For the three months ended December 31, 2018, petroleum and natural gas revenues increased 9% over the comparable period of 2017, due primarily to a 31% increase in production offset by a 17% decrease in realized prices for the quarter.

For the year ended December 31, 2018, petroleum and natural gas revenues increased 47% over the comparable period of 2017, due primarily to a 35% increase in production and a 9% increase in realized selling prices.

Condensate & oil volumes of 30% of total production in the fourth quarter of 2018, amounted to 49% of total petroleum and natural gas revenues. As a result of weaker condensate prices in the fourth quarter of 2018, the condensate sales as a percentage of total petroleum and natural gas revenues was lower than the comparative historical average of approximately 60%.

Natural gas revenue

A breakdown of natural gas revenue is as follows:

	Three months ended December 31				Year ended December 31			
	2018		2017		**2018**		2017	
($ thousands, except per unit amounts)	**$**	**$/Mcf**	$	$/Mcf	**$**	**$/Mcf**	$	$/Mcf
Natural gas revenue - AECO reference price [(1)]	**28,566**	**1.90**	24,284	1.96	**79,439**	**1.53**	93,659	2.43
Heat/value adjustment [(2)]	**2,620**	**0.17**	2,233	0.18	**7,618**	**0.15**	8,861	0.22
Transportation revenue [(3)]	**7,194**	**0.48**	3,706	0.30	**26,467**	**0.52**	8,035	0.20
Natural gas market diversification revenue	**19,649**	**1.07**	2,286	0.24	**53,342**	**0.96**	8,418	0.16
AECO physical delivery sales contract gains [(4)]	**1,107**	**0.07**	8,886	0.73	**18,304**	**0.35**	21,377	0.54
Total natural gas revenue	**59,136**	**3.69**	41,395	3.41	**185,170**	**3.51**	140,350	3.55

(1) 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 December 31, 2018, natural gas revenue increased 43% over the comparable period of 2017, due to a 32% increase in production and an 8% increase in realized selling prices.

For the year ended December 31, 2018, natural gas revenue increased 32% over the comparable period of 2017, due primarily to a 34% increase in production offsetting a 1% decrease in realized selling prices.

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

	Three months ended December 31		Year ended December 31	
	2018	2017	**2018**	**2017**
AECO physical spot price deliveries	**15%**	—%	**2%**	3%
AECO physical fixed price sales contracts	**20%**	59%	**31%**	63%
Dawn physical deliveries	**26%**	22%	**29%**	7%
Malin physical deliveries	**23%**	—%	**19%**	—%
Chicago physical deliveries	**16%**	19%	**19%**	27%

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 and transportation arrangements that the Company has in place to diversify and gain exposure to alternative natural gas markets in North America to limit its exposure to spot AECO pricing. For the three months ended December 31, 2018, the Company had 15% exposure to AECO spot prices as a result of the Pipestone Acquisition. Natural gas sales under AECO physical fixed price delivery sales contracts represented approximately 20% of the Company's total natural gas production. NuVista delivered approximately 26% of its natural gas production to Dawn, 23% to Malin, and 16% to Chicago.

NuVista's exposure to AECO floating prices was limited to approximately 10% of forecast volumes in the fourth quarter of 2018 as a result of this market egress, and the inclusion of pre-existing 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 NYMEX basis natural gas sales price derivative contracts will result in long term price diversification and exposure to AECO floating pricing limited to approximately 10%-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, 2018 was $3.62/Mcf and $3.16/Mcf respectively, compared to $2.68/Mcf and $3.01/Mcf for the comparative periods of 2017, and $2.97/Mcf in the third quarter of 2018.

Condensate & oil revenue

For the three months ended December 31, 2018, condensate & oil revenue decreased 15% over the comparable period of 2017 due to a 13% increase in production offset by a 25% decrease in realized selling prices.

For the year ended December 31, 2018, condensate & oil revenue increased 49% over the comparable period of 2017, due primarily to a 29% increase in production and a 16% increase in realized selling prices.

Strong demand for condensate & oil in Alberta results in benchmark condensate prices at Edmonton trading at a premium to Canadian light oil prices. NuVista's realized condensate & oil prices include adjustments for pipeline tariffs to Edmonton and quality differentials. Condensate & oil realized selling prices averaged $51.60/Bbl and $70.92/Bbl in the three months and year ended December 31, 2018, a decrease of 25% and and increase of 16% from $68.36/Bbl and $61.01/Bbl for the comparable periods of 2017.

NGL revenue

For the three months ended December 31, 2018, NGL revenue increased 88% over the comparable period of 2017, due to a 119% increase in production partially offset by a 14% decrease in realized selling prices.

For the year ended December 31, 2018, NGL revenue increased 139% over the comparable period of 2017, due primarily to a 88% increase in production and a 27% 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 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 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 December 31					
($ thousands)	**2018**			2017		
	Realized gain (loss)	**Unrealized gain (loss)**	**Total gain (loss)**	Realized gain (loss)	Unrealized gain (loss)	Total gain (loss)
Natural gas	**(6,279)**	**36,121**	**29,842**	1,311	29,950	31,261
Condensate & oil	**(4,296)**	**93,917**	**89,621**	(743)	(23,952)	(24,695)
Foreign exchange	**(108)**	**(78)**	**(186)**	—	—	—
Gain (loss) on financial derivatives	**(10,683)**	**129,960**	**119,277**	568	5,998	6,566

During the fourth quarter of 2018, the commodity price risk management program resulted in a total gain of $119.3 million, compared to a total gain of $6.6 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. The significant unrealized gain in the fourth quarter is predominately as a result of lower WTI forward curves as well as lower fourth quarter oil prices compared to the third quarter, and the resulting increase in the value of oil derivative contracts. Due to the increased volatility in oil and gas prices and the related forward-looking strips, the corresponding impact of unrealized gains and/or losses on overall earnings in a particular reporting period can be substantial, as was the case in the fourth quarter of 2018.

	Year ended December 31					
($ thousands)	**2018**			2017		
	Realized gain (loss)	**Unrealized gain (loss)**	**Total gain (loss)**	Realized gain (loss)	Unrealized gain (loss)	Total gain (loss)
Natural gas	**(1,057)**	**32,122**	**31,065**	3,963	31,659	35,622
Condensate & oil	**(37,224)**	**61,273**	**24,049**	1,101	(35)	1,066
Foreign exchange	**(54)**	**—**	**(54)**	—	—	—
Gain (loss) on financial derivatives	**(38,335)**	**93,395**	**55,060**	5,064	31,624	36,688

For the year ended December 31, 2018, the commodity price risk management program resulted in a gain of $55.1 million compared to a realized gain of $36.7 million for the comparable period of 2017.

Price risk management gains on our physical delivery sale contracts totaled $1.1 million and $18.3 million for the three months and year ended December 31, 2018 compared to gains of $8.9 million and $21.4 million for the comparable periods of 2017.

(a) Financial instruments

The following is a summary of financial derivatives contracts in place as at December 31, 2018:

	WTI fixed price swap	
Term (1)	Bbls/d	Cdn$/Bbl
2019	4,468	77.06
2020	699	88.69

(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	4,427	68.67	83.26	90.28
2020	2,299	67.83	83.61	90.54

(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
2019	21,322	(0.87)	10,836	(0.25)	18,329	(0.40)	10,000	0.68	1,671	(0.26)
2020	47,500	(0.96)	15,000	(0.25)	11,667	(0.51)	8,333	0.68	10,000	(0.26)
2021	95,000	(0.98)	15,000	(0.24)	20,000	(0.66)	—	—	10,000	(0.26)
2022	95,000	(0.97)	12,493	(0.24)	16,658	(0.66)	—	—	8,329	(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
2019	38,712	2.88	8,329	2.50

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

Subsequent to December 31, 2018 the following is a summary of financial derivatives that have been entered into:

	WTI fixed price swap	
Term (1)	Bbls/d	Cdn$/Bbl
2019	821	73.58
2020	1,200	73.68

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

Term [1]	AECO fixed price swap GJ/d	Cdn$/GJ	NYMEX fixed price swap MMbtu/d	US$/MMbtu
2019	2,932	1.30	2,507	2.78
2020	—	—	12,500	2.78

[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 December 31, 2018:

	AECO fixed price swap		Dawn fixed price swap		Dawn-NYMEX Basis	
Term [1]	GJ/d	Cdn$/GJ	MMbtu/d	US$/MMbtu	MMbtu/d	US$/MMbtu
2019	28,849	1.59	8,329	2.50	1,671	(0.26)
2020	—	—	—	—	10,000	(0.26)
2021	—	—	—	—	10,000	(0.26)
2022	—	—	—	—	8,329	(0.26)

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

Subsequent to December 31, 2018 the following is a summary of the physical delivery sales contracts that have been entered into:

Term [1]	AECO fixed price swap GJ/d	Cdn$/GJ
2019	13,397	1.33
2020	8,333	1.60

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

Royalties

	Three months ended December 31		Year ended December 31	
($ thousands, except % and per Boe amounts)	**2018**	2017	**2018**	2017
Gross royalties	**8,104**	7,062	**27,691**	20,281
Gas cost allowance ("GCA")	**(3,256)**	(2,293)	**(11,418)**	(8,132)
Net royalties	**4,848**	4,769	**16,273**	12,149
Gross royalty % excluding physical delivery sales contracts[1]	**5.7**	5.8	**5.2**	5.7
Gross royalty % including physical delivery sales contracts	**5.7**	5.4	**5.0**	5.4
Net royalties $/Boe	**1.07**	1.38	**1.10**	1.12

[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, 2018, gross royalties increased 15% and 37% respectively as compared to the comparable periods of 2017 as a result of the production increases over the prior year. Gross royalties as a percentage of petroleum and natural gas revenues remained consistent with the prior year comparative periods.

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 months and year ended December 31, 2018, the 42% and 40% 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 December 31		Year ended December 31	
($ thousands, except per unit amounts)	**2018**	2017	**2018**	2017
Natural gas transportation expense	**11,830**	7,511	**41,333**	24,114
Condensate, oil & NGL transportation expense	**1,408**	1,347	**3,766**	4,837
Total transportation expense	**13,238**	8,858	**45,099**	28,951
Natural gas transportation $/Mcf [(1)]	**0.74**	0.62	**0.78**	0.61
Condensate, oil & NGL transportation $/Bbl	**1.04**	1.12	**0.81**	1.34
Total transportation $/Boe	**2.93**	2.57	**3.06**	2.66

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

For the three months and year ended December 31, 2018, total transportation expenses on a total dollar and per Boe basis increased from the comparative periods of 2017 due primarily 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. Compared to third quarter transportation expense of $11.4 million ($3.09/Boe), transportation expenses for the fourth quarter increased as a result of increased production.

Condensate transportation expense on a $/Bbl basis is dependent on the proportion of condensate production volumes flowing through third party liquids pipelines which incurs lower transportation rates than volumes being trucked. The lower condensate transportation rates for the three months and year ended December 31, 2018 as compared to the prior year comparative periods were primarily as a result of increased condensate production and a higher proportion of condensate volumes flowing through third party liquids pipelines versus the prior year which incurs minimal transportation expense, resulting in a lower condensate transportation $/Bbl.

Operating expenses

	Three months ended December 31		Year ended December 31	
($ thousands, except per unit amounts)	**2018**	2017	**2018**	2017
Operating expenses	**40,886**	33,247	**143,603**	111,465
Per Boe	**9.06**	9.65	**9.75**	10.25

For the three months and year ended December 31, 2018, operating expenses increased 23% and 29% respectively as a result of the increased production compared to the prior year comparative periods of 2017, while the per Boe costs decreased 6% from the comparative periods due to increased production, operational efficiencies, and increased utilization of the Elmworth and Bilbo compressor stations. Compared to third quarter operating expenses of $36.2 million ($9.82/Boe), fourth quarter operating expenses per Boe decreased primarily as a result of increased production from a full quarter of production from the Pipestone Acquisition which carry a lower per Boe operating expense, and a decrease in water handling expenses as a result of high utilization of owned water disposal facilities and higher utilization of third party water disposal facilities in closer proximity to the Company's assets, resulting in a decrease in trucking expenses.

General and administrative expenses ("G&A")

	Three months ended December 31		Year ended December 31	
($ thousands, except per Boe amounts)	**2018**	2017	**2018**	2017
Gross G&A expenses	**5,768**	6,372	**23,358**	22,567
Overhead recoveries	**(497)**	(47)	**(934)**	(453)
Capitalized G&A	**(1,191)**	(1,189)	**(4,884)**	(4,737)
Net G&A expenses	**4,080**	5,136	**17,540**	17,377
Gross G&A per Boe	**1.28**	1.85	**1.59**	2.08
Net G&A per Boe	**0.90**	1.49	**1.19**	1.60

As a result of continued efficiency focus on Wapiti Montney, as well as the natural efficiencies associated with the Pipestone Acquisition, NuVista has continued to drive G&A costs per Boe downwards. For the year ended December 31, 2018, gross G&A expenses have increased slightly due to the few increased staff associated with growing Montney production activities and the Pipestone Acquisition. 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 December 31		Year ended December 31	
($ thousands)	**2018**	2017	**2018**	2017
Stock options	**919**	966	**3,515**	3,387
Director deferred share units	**(725)**	486	**(366)**	1,038
Restricted share awards	**414**	440	**1,668**	1,544
Performance share awards	**97**	—	**225**	—
Total	**705**	1,892	**5,042**	5,969

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 second quarter of 2018, the share award plan was revised to include both RSAs and PSAs.

The decrease in share-based compensation for the three months ended December 31, 2018 compared to the comparable period of 2017 is due primarily to the decrease in the DSU liability in the fourth quarter of 2018 as a result of the decrease in share price from $7.50/share at September 30, 2018 to $4.08/share at December 31, 2018.

On a year to date basis, total share based compensation decreased, with a slight increase in the weighted average fair value of stock options granted in 2018 and the addition of PSAs in the year, offset by a decrease in the share price used to value DSUs over the comparable period of 2017.

Transaction costs

	Three months ended December 31		Year ended December 31	
($ thousands, except per Boe amounts)	**2018**	2017	**2018**	2017
Total transaction costs	**—**	—	**2,624**	—
Total transaction costs per Boe	**—**	—	**0.18**	—

Transaction costs are those costs related to the Pipestone Acquisition that occurred in the third quarter of 2018. These costs include advisory, legal and other professional fees.

Financing costs

	Three months ended December 31		Year ended December 31	
($ thousands, except per Boe amounts)	**2018**	2017	**2018**	2017
Interest on long-term debt (credit facility)	**2,548**	1,274	**5,509**	4,364
Interest on senior unsecured notes [(1)]	**3,813**	1,875	**16,222**	7,436
Call premium on redemption of 2021 Notes	**—**	—	**6,562**	—
Interest expense	**6,361**	3,149	**28,293**	11,800
Accretion expense	**540**	387	**1,776**	1,524
Total financing costs	**6,901**	3,536	**30,069**	13,324
Interest expense per Boe	**1.41**	0.91	**1.92**	1.09
Total financing costs per Boe	**1.53**	1.03	**2.04**	1.23

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

For the three months and year ended December 31, 2018 interest expense on long-term debt increased from the comparable periods in 2017 due to higher average bank indebtedness and interest rates throughout the periods. Average interest rates on long term debt for the three months and year ended December 31, 2018 were 3.5% and 3.3% compared to average interest rates of 3.2% and 3.0% for the comparative periods of 2017. Interest rates have increased in 2018 commensurate with an increase in the Bank of Canada overnight lending rates. Interest expense on long-term debt includes interest standby charges on the Company's syndicated credit facilities.

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 months and year ended December 31, 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 December 31, 2018 is $215.9 million.

Operating netback and corporate netback

The tables below summarizes operating netback and corporate netback on a total dollar and per Boe basis for the three months and year ended December 31, 2018 and 2017:

	Three months ended December 31, 2018		Three months ended December 31, 2017	
($ thousands, except per Boe amounts)	**$**	**$/Boe**	$	$/Boe
Petroleum and natural gas revenues [1]	**143,006**	**31.69**	131,009	38.04
Realized gain (loss) on financial derivatives	**(10,683)**	**(2.37)**	568	0.16
	132,323	**29.32**	131,577	38.20
Royalties	**(4,848)**	**(1.07)**	(4,769)	(1.38)
Transportation expense	**(13,238)**	**(2.93)**	(8,858)	(2.57)
Operating expense	**(40,886)**	**(9.06)**	(33,247)	(9.65)
Operating netback [2]	**73,351**	**16.26**	84,703	24.60
General and administrative expense	**(4,080)**	**(0.90)**	(5,136)	(1.49)
Deferred share units expense (recovery)	**725**	**0.16**	(486)	(0.14)
Interest expense	**(6,361)**	**(1.41)**	(3,149)	(0.91)
Corporate netback [2]	**63,635**	**14.11**	75,932	22.06

[1] Includes price risk management gains of $1.1 million (2017 - $8.9 million gain) on physical delivery sales contracts.
[2] Non-GAAP measure that does not have any standardized meaning under IFRS and therefore may not be comparable to similar measures presented by other companies where similar terminology is used. Reference should be made to the section entitled "Non-GAAP measurements".

	Year ended December 31, 2018		Year ended December 31, 2017	
($ thousands, except per Boe amounts)	**$**	**$/Boe**	$	$/Boe
Petroleum and natural gas revenues [1]	**555,849**	**37.74**	377,746	34.75
Realized gain (loss) on financial derivatives	**(38,335)**	**(2.60)**	5,064	0.47
	517,514	**35.14**	382,810	35.22
Royalties	**(16,273)**	**(1.10)**	(12,149)	(1.12)
Transportation expense	**(45,099)**	**(3.06)**	(28,951)	(2.66)
Operating expense	**(143,603)**	**(9.75)**	(111,465)	(10.25)
Operating netback [2]	**312,539**	**21.23**	230,245	21.19
General and administrative	**(17,540)**	**(1.19)**	(17,377)	(1.60)
Deferred share units expense (recovery)	**366**	**0.02**	(1,038)	(0.10)
Interest expense	**(28,293)**	**(1.92)**	(11,800)	(1.09)
Transaction costs	**(2,624)**	**(0.18)**	—	—
Corporate netback [2]	**264,448**	**17.96**	200,030	18.40

[1] Includes price risk management gains of $18.3 million (2017 - $21.4 million gain) on physical delivery sales contracts.
[2] Non-GAAP measure that does not have any standardized meaning under IFRS and therefore may not be comparable to similar measures presented by other companies where similar terminology is used. Reference should be made to the section entitled "Non-GAAP measurements".

Cash flow from operating activities and adjusted funds flow

The following table is NuVista's cash flow from operating activities and adjusted funds flow [(1)] for the three months and year ended December 31:

	Three months ended December 31		Year ended December 31	
($ thousands, except per share amounts)	**2018**	2017	**2018**	2017
Cash flow from operating activities	**70,447**	109,078	**251,057**	224,680
Per share, basic	**0.31**	0.63	**1.32**	1.30
Per share, diluted	**0.31**	0.62	**1.31**	1.29
Adjusted funds flow [(1)]	**63,635**	75,932	**264,448**	200,030
Per share, basic	**0.28**	0.44	**1.39**	1.15
Per share, diluted	**0.28**	0.43	**1.38**	1.15

[(1)] Non-GAAP measure that does not have any standardized meaning under IFRS and therefore may not be comparable to similar measures presented by other companies where similar terminology is used. Reference should be made to the section entitled "Non-GAAP measurements".

For the three months ended December 31, 2018, cash flow from operating activities of $70.4 million decreased 35% from $109.1 million in the comparable period of 2017 primarily due to lower realized commodity pricing, a realized loss on financial derivatives compared to a realized gain in the prior year comparative period, and higher interest expense as a result of increased indebtedness.

Adjusted funds flow for the three months ended December 31, 2018 and December 31, 2017 was $63.6 million ($0.28/share, basic) and $75.9 million ($0.43/share, basic) respectively, $6.8 million and $33.1 million lower than cash flow from operating activities in the comparable periods, due to changes in asset retirement expenditures and non-cash working capital.

For the year ended December 31, 2018, cash flow from operating activities of $251.1 million increased 12% from the comparable period of 2017, primarily due to increased petroleum and natural gas revenues as a result of increased production, partially offset by a realized loss on financial derivatives compared to a realized gain in the prior year comparative period and higher interest expense as a result of increased indebtedness.

Adjusted funds flow for the years ending December 31, 2018 and December 31, 2017 was 264.4 million ($1.39/share, basic) and $200.0 million ($1.15 /share, basic) respectively, $13.4 milliion higher and $24.7 million lower than cash flow from operating activities in the comparable periods, due to changes in asset retirement expenditures and non-cash working capital.

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

	Three months ended December 31		Year ended December 31	
($ thousands, except per Boe amounts)	**2018**	2017	**2018**	2017
Depletion of oil and gas assets	**42,740**	48,262	**142,270**	121,913
Depreciation of fixed assets	**3,716**	3,671	**13,810**	13,675
DD&A expense	**46,456**	51,933	**156,080**	135,588
Exploration and evaluation ("E&E") impairment expense	**—**	1,427	**—**	1,427
Total DD&A and impairment expense	**46,456**	53,360	**156,080**	137,015
DD&A rate per Boe	**10.29**	15.08	**10.60**	12.47

DD&A expense for three months and year ended December 31, 2018 was $46.5 million ($10.29/Boe) compared to $51.9 million ($15.08/Boe) for the comparable period of 2017, and $38.3 million ($10.38/Boe) in the third quarter of 2018. The DD&A rate for the three months and year ended December 31, 2018 was positively impacted by the Acquired Assets and the continued successful development of Wapiti Montney. At December 31, 2017, substantially all of the net book value of PP&E for cash generating units ("CGUs") excluding Wapiti Montney was fully depleted as a result of minimal reserves assigned to those CGUs in the year end reserve report. DD&A expense for the three months and year ended December 31, 2018 includes depletion expense of $3.2 million ($0.71/Boe) and $7.8 million ($0.53/Boe), respectively, primarily related to an increase in estimate on asset retirement obligations for wells with no remaining reserves that as a result were previously fully depleted. The full amount of this asset retirement obligation is included in depletion expense.

The Wapiti Montney CGU DD&A rate per Boe for three months and year ended December 31, 2018 decreased to $9.62/Boe and $10.12/Boe respectively, compared to $9.87/Boe and $10.55/Boe for the comparable periods of 2017, and decreased from the DD&A rate of $10.54/Boe in the third quarter of 2018. These improved DD&A rates compared to 2017 is a result of continued successful development and favorable acquisition metrics for the Acquired Assets.

At December 31, 2018, there were no indicators of impairment or reversal of impairment identified on any of the Company's CGU's within property, plant & equipment and an impairment test was not performed.

Exploration and evaluation ("E&E") expense

	Three months ended December 31		Year ended December 31	
($ thousands, except per Boe amounts)	**2018**	2017	**2018**	2017
Exploration and evaluation expense	**921**	6,888	**2,710**	6,932
Per Boe	**0.20**	2.00	**0.18**	0.64

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

Asset retirement obligations

($ thousands)	**December 31, 2018**	December 31, 2017
Balance, January 1	**72,430**	75,463
Accretion expense	**1,776**	1,524
Liabilities acquired	**11,141**	—
Change in discount rate, Pipestone Acquisition	**17,571**	—
Liabilities incurred	**3,291**	3,698
Liabilities disposed	**(14)**	(3,272)
Change in estimates and discount rate	**9,966**	4,830
Liabilities settled	**(13,458)**	(9,813)
Balance, end of period	**102,703**	72,430
Expected to be incurred within one year	**12,500**	14,250
Expected to be incurred beyond one year	**90,203**	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 December 31, 2018, NuVista had an ARO balance of $102.7 million as compared to $72.4 million as at December 31, 2017. The liability was discounted using the Bank of Canada's long-term risk-free bond rate of 2.2% at December 31, 2018 (December 31, 2017 – 2.4%). At December 31, 2018, the estimated total undiscounted and uninflated amount of cash required to settle NuVista's ARO was $106.0 million (December 31, 2017 – $75.9 million). The majority of the costs are expected to be incurred within the next 50 years. Actual ARO expenditures for the year ended December 31, 2018 were $13.5 million compared to $9.8 million for the year ended December 31, 2017.

Asset retirement obligations acquired pursuant to the Pipestone Acquisition in the third quarter of 2018 were initially recognized in accordance with IFRS at fair value using a credit adjusted rate of 7.5%. They were subsequently revalued using the respective Bank of Canada long term risk-free bond rate of 2.4%, resulting in the recognition of an additional $17.6 million in asset retirement obligations.

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, except % amounts)	**2018**	% of total	2017	% of total	**2018**	% of total	2017	% of total
Land and retention costs	**(78)**	—	(493)	(1)	**1,801**	1	510	—
Geological and geophysical	**1,392**	2	1,303	3	**6,415**	2	5,201	2
Drilling and completion	**50,532**	65	30,677	77	**257,626**	76	246,727	78
Facilities and equipment	**25,586**	33	7,801	19	**74,512**	22	61,350	20
Corporate and other	**1**	—	811	2	**438**	—	1,514	—
Capital expenditures (1)	**77,433**		40,099		**340,792**		315,302	

(1) Non-GAAP measure that does not have any standardized meaning under IFRS and therefore may not be comparable to similar measures presented by other companies where similar terminology is used. Reference should be made to the section entitled "Non-GAAP measurements".

Capital expenditures for the year ended ended December 31, 2018 were $340.8 million. The Company focused 76% of its exploration and development expenditures on drilling and completion activities, with 22% on facilities and equipment.

Of the $340.8 million capital spent to date in 2018, $335.9 million was spent on property, plant and equipment expenditures, and $4.9 million was spent on exploration and evaluation expenditures.

Acquisitions

On September 6, 2018, the Company closed the Pipestone Acquisition in which the Company acquired petroleum and natural gas properties and facilities to expand its Montney core area and increase future development opportunities. Total consideration paid and estimates of the fair value of the assets acquired and liabilities assumed as of the date of the acquisition are set forth in the table below. All amounts are final.

($ thousands)	
Net proceeds from equity issuance	366,594
Borrowings on credit facility	252,850
Cash consideration paid	**619,444**

($ thousands)	
Property, plant and equipment	676,436
Exploration and evaluation	28,122
Asset retirement obligations	(11,141)
Deferred tax liabilities	(73,973)
Fair value of net assets acquired	**619,444**

Dispositions

For the year ended December 31, 2018, there were no property dispositions as compared to property dispositions with cash proceeds of $2.2 million in the comparable period of 2017, resulting in a loss of $6.8 million.

Deferred income taxes

For the three months and year ended December 31, 2018, the provision for income taxes was an expense of $40.2 million, and $55.5 million compared to an expense of $17.4 million in the comparable periods of 2017.

Tax pools

At December 31, 2018, NuVista had approximately $1.6 billion (2017 – $1.1 billion) 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.

	Available tax pools	Maximum annual deduction
($ millions)	**2018**	%
Canadian exploration expense	**256**	100%
Canadian development expense	**406**	30-45% declining balance
Canadian oil and natural gas property expense	**435**	10-15% declining balance
Undepreciated capital cost	**218**	25-37.5% declining balance
Non-capital losses	**274**	100%
Other	**26**	various rates
Total federal tax pools	**1,615**	
Additional Alberta tax pools	**8**	100%

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 December 31		Year ended December 31	
($ thousands, except per share amounts)	**2018**	2017	**2018**	2017
Net earnings	**104,086**	34,651	**136,245**	94,368
Per share - basic	**0.46**	0.20	**0.71**	0.54
Per share - diluted	**0.46**	0.20	**0.71**	0.54

The increase in net earnings for the three months ended December 31, 2018 compared to the prior year comparative period is primarily a result of increased unrealized hedging gains and decreased DD&A , offset by decreased adjusted funds flow and the incremental interest on the higher principal balance of the 2023 Notes.

For the year ended December 31, 2018, the increase in net earnings compared to the prior year comparative period is primarily as a result of increased unrealized hedging gains and increased adjusted funds flow, offset by higher DD&A, deferred taxes, and an realized loss on financial derivatives as compared to a realized gain in the prior year comparative period.

Liquidity and capital resources

Long-term debt (credit facility)

At December 31, 2018, the Company had a $450 million (December 31, 2017 - $310 million) extendible revolving term credit facility available from a syndicate of Canadian chartered banks. The credit facility was increased from $310.0 million upon closing of the Pipestone Acquisition on September 6, 2018. 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 the lenders 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, 2018, NuVista was in compliance with all covenants. The semi annual review was completed in the fourth quarter, with no change to the credit facility The next review is scheduled for on or before April 30, 2019.

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.

Equity financings

In August 2018, as part of the financing of the Pipestone Acquisition, the Company issued 47.4 million common shares at a price of $8.10 per share, for gross proceeds of $384.1 million. Common shares totaling 21.0 million were issued pursuant to a public offering, and an additional 26.4 million were issued pursuant to a private placement. The Company also issued 2.8 million common shares on a flow-through basis in respect of Canadian Development expenses ("CDE") at a price of $9.05 per share for gross proceeds of $24.9 million, of which 0.4 million common shares were issued pursuant to a private placement. Under the terms of the flow-through share agreements, the Company is committed to spend approximately $24.9 million on qualifying CDE prior to December 31, 2018. The balance of the purchase price was funded through the Company's increased credit facility. At December 31, 2018, NuVista has fulfilled its commitment to spend $24.9 million on qualifying CDE.

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

($ thousands)	**December 31, 2018**	December 31, 2017
Basic common shares outstanding	**225,306**	174,004
Share price[(1)]	**4.08**	8.02
Total market capitalization	**919,248**	1,395,512
Cash and cash equivalents, accounts receivable and prepaid expenses	**(53,334)**	(47,941)
Accounts payable and accrued liabilities	**90,074**	50,725
Long-term debt (credit facility)	**257,395**	125,725
Senior unsecured notes	**215,892**	67,680
Other liabilities	**1,381**	1,747
Net debt [(2)]	**511,408**	197,936
Annualized current quarter adjusted funds flow	**254,540**	303,728
Net debt to annualized current quarter adjusted funds flow	**2.0**	0.7
Adjusted funds flow [(2)]	**264,448**	200,030
Net debt to adjusted funds flow	**1.9**	1.0

(1) Represents the closing share price on the Toronto Stock Exchange on the last trading day of the period.

(2) Non-GAAP measure that does not have any standardized meaning under IFRS and therefore may not be comparable to similar measures presented by other companies where similar terminology is used. Reference should be made to the section entitled "Non-GAAP measurements".

Net debt

As at December 31, 2018, net debt was $511.4 million, resulting in a net debt to annualized current quarter adjusted funds flow ratio of 2.0 times. NuVista's long term strategy is to maintain a net debt to annualized current quarter adjusted funds flow ratio of approximately 1.5 times. 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, 2018, NuVista had drawn $257.4 million on its long-term debt (credit facility) and had outstanding letters of credit of $7.8 million which reduce the credit available on the credit facility, leaving $184.8 million of unused credit facility capacity based on the committed credit facility of $450.0 million.

NuVista plans to monitor its 2019 business plan and adjust its 2019 budgeted capital program of $300 - $325 million in the context of commodity prices and net debt levels.

As at December 31, 2018, there were 225.3 million common shares outstanding. In addition, there were 6.9 million stock options with an average exercise price of $6.78 per option , 0.5 million RSAs, and 0.3 million PSAs outstanding.

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, 2018:

($ thousands)	**Total**	2019	2020	2021	2022	2023	Thereafter
Transportation(1)	**863,031**	63,263	77,635	97,993	103,668	86,650	433,822
Processing (1)	**1,182,786**	45,034	58,745	81,337	95,455	96,039	806,176
Office lease	**12,813**	1,814	1,826	1,887	1,893	1,946	3,447
Total commitments	**2,058,630**	110,111	138,206	181,217	201,016	184,635	1,243,445

(1) Certain of the transportation and processing commitments are secured by outstanding letters of credit of $7.3 million at December 31, 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.

Annual financial information

The following table highlights selected annual financial information for the years ended December 31, 2018, 2017 and 2016:

($ thousands, except per share amounts)	**2018**	2017	2016
Petroleum and natural gas revenues	**555,849**	377,746	257,252
Net earnings (loss)	**136,245**	94,368	(1,653)
Per basic and diluted share	**0.71**	0.54	(0.01)
Balance sheet information			
Total assets	**2,180,874**	1,186,419	961,240
Long-term debt	**257,395**	125,725	—
Senior unsecured notes	**215,892**	67,680	67,156
Shareholders' equity	**1,405,017**	863,579	756,029

Quarterly financial information

The following table highlights NuVista’s performance for the eight quarterly reporting periods from March 31, 2017 to December 31, 2018:

($ thousands, except	**2018**				2017			
per share amounts)	**Dec 31**	Sep 30	Jun 30	Mar 31	Dec 31	Sep 30	Jun 30	Mar 31
Production (Boe/d)	**49,060**	40,080	36,035	36,099	37,435	29,405	25,454	26,731
Petroleum and natural gas revenues	**143,006**	150,956	137,131	124,756	131,009	83,100	79,401	84,236
Net earnings (loss)	**104,086**	3,467	6,322	22,371	34,651	(4,366)	25,767	38,317
Per basic share	**0.46**	0.02	0.04	0.13	0.20	(0.03)	0.15	0.22
Cash flow from operating activities	**70,447**	51,740	63,576	65,294	109,078	39,278	40,298	36,026
Per basic share	**0.31**	0.28	0.36	0.38	0.63	0.23	0.23	0.21
Adjusted funds flow [(1)]	**63,635**	72,610	69,472	58,732	75,932	41,526	39,318	43,254
Per basic share	**0.28**	0.39	0.40	0.34	0.44	0.24	0.23	0.25

(1) Non-GAAP measure that does not have any standardized meaning under IFRS and therefore may not be comparable to similar measures presented by other companies where similar terminology is used. Reference should be made to the section entitled "Non-GAAP measurements".

NuVista's Montney production volumes have been increasing with substantially all of the Company's capital expenditures allocated to the Wapiti Montney area, related successful drilling and production performance, and asset acquisitions 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 $79.4 million to $151.0 million with revenue primarily influenced by production volumes and commodity prices. Net earnings (losses) have been in a range of a net loss of $4.4 million to net earnings of $104.1 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.

Non-GAAP measurements

The Company uses terms that are commonly used in the oil and natural gas industry, but do not have any standardized meaning as prescribed by IFRS and therefore may not be comparable with the calculations of similar measures for other entities. Management believes that the presentation of these non-GAAP measures provide useful information to investors and shareholders as the measures provide increased transparency and the ability to better analyze performance against prior periods on a comparable basis

The following list identifies the non-GAAP measures included in NuVista's MD&A, a description of how the measure has been calculated, a discussion of why management has deemed the measure to be useful and a reconciliation to the most comparable GAAP measure.

Adjusted funds flow

NuVista has calculated adjusted funds flow based on cash flow provided by operating activities, excluding changes in non-cash working capital, asset retirement expenditures and environmental remediation recovery, as management believes the timing of collection, payment, and occurrence is variable and by excluding them from the calculation, management is able to provide a more meaningful measure of NuVista's operations on a continuing basis. More specifically, expenditures on asset retirement obligations may vary from period to period depending on the Company's capital programs and the maturity of its operating areas, while environmental remediation recovery relates to an incident that management doesn't expect to occur on a regular basis. The settlement of asset retirement obligations is managed through NuVista's capital budgeting process which considers its available adjusted funds flow.

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 earnings (loss) per share. Refer to Note 16 "Capital Management" in the financial statements.

NuVista considers adjusted funds flow to be a key measure that provides a more complete understanding of the Company's ability to generate cash flow necessary to finance capital expenditures, expenditures on asset retirement obligations, and meet its financial obligations.

The following table provides a reconciliation between the non-GAAP measure of adjusted funds flow to the more directly comparable GAAP measure of cash flow from operating activities:

	Three months ended December 31		Year ended December 31	
($ thousands)	**2018**	2017	**2018**	2017
Cash provided by operating activities	**70,447**	109,078	**251,057**	224,680
Add back:				
Environmental remediation recovery	**—**	—	**—**	(2,550)
Asset retirement expenditures	**2,835**	1,944	**13,458**	9,813
Change in non-cash working capital [2]	**(9,647)**	(35,090)	**(67)**	(31,913)
Adjusted funds flow [1]	**63,635**	75,932	**264,448**	200,030
Adjusted funds flow per share, basic	**0.28**	0.44	**1.39**	1.15
Adjusted funds flow per share, diluted	**0.28**	0.43	**1.38**	1.15

[1] Year to date value includes transaction costs relating to the Pipestone Acquisition on September 6, 2018 of $2.6 million.
[2] Refer to Note 20 "Supplemental cash flow information" in the financial statements.

Operating netback and Corporate netback ("netbacks")

NuVista reports netbacks on a total dollar and per Boe basis. Operating netback is calculated as petroleum and natural gas revenues including realized financial derivative gains/losses, less royalties, transportation and operating expenses. Corporate netback is operating netback less general and administrative, deferred share units, and interest expense. Netbacks per Boe are calculated by dividing the netbacks by total production volumes sold in the period.

Management feels both operating and corporate netbacks are key industry benchmarks and measures of operating performance for NuVista that assists management and investors in assessing NuVista's profitability, and are commonly used by other petroleum and natural gas producers. The measurement on a Boe basis assists management and investors with evaluating NuVista's operating performance on a comparable basis.

The following table provides a reconciliation between the non-GAAP measures of operating and corporate netback to the most directly comparable GAAP measure of net income (loss) for the period:

($ thousands)	Three months ended December 31 2018	2017	Year ended December 31 2018	2017
Net earnings and comprehensive income	**104,086**	34,651	**136,245**	94,368
Add back:				
Depletion, depreciation, amortization and impairment	**46,456**	53,360	**156,080**	137,015
Exploration and evaluation	**921**	6,888	**2,710**	6,932
Loss on property dispositions	**—**	2,611	**146**	6,808
Share-based compensation	**705**	1,893	**5,042**	5,969
Unrealized gain on financial derivatives	**(129,960)**	(5,998)	**(93,395)**	(31,624)
Deferred income tax expense (recovery)	**40,162**	(17,374)	**55,478**	(17,374)
Environmental remediation recovery	**—**	—	**—**	(2,550)
General and administrative expenses	**4,080**	5,136	**17,540**	17,377
Transaction costs	**—**	—	**2,624**	—
Financing costs	**6,901**	3,536	**30,069**	13,324
Operating netback	**73,351**	84,703	**312,539**	230,245
Deduct:				
General and administrative expenses	**(4,080)**	(5,136)	**(17,540)**	(17,377)
Deferred share units recovery (expense)	**725**	(486)	**366**	(1,038)
Interest expense	**(6,361)**	(3,149)	**(28,293)**	(11,800)
Transaction costs	**—**	—	**(2,624)**	—
Corporate netback	**63,635**	75,932	**264,448**	200,030

Capital expenditures

Capital expenditures is equal to cash flow used in investing activities, excluding changes in non-cash working capital. NuVista considers capital expenditures to be a useful measure of cash flow used for capital reinvestment.

The following table provides a reconciliation between the non-GAAP measure of capital expenditures to the most directly comparable GAAP measure of cash flow used in investing activities for the period:

($ thousands)	Three months ended December 31 2018	2017	Year ended December 31 2018	2017
Cash flow used in investing activities	**(50,428)**	(87,267)	**(925,963)**	(361,483)
Changes in non-cash working capital	**(28,684)**	47,168	**(34,273)**	48,422
Property acquisitions	**1,679**	—	**619,444**	—
Proceeds on property dispositions	**—**	—	**—**	(2,241)
Capital expenditures	**(77,433)**	(40,099)	**(340,792)**	(315,302)

Net debt

NuVista has calculated net debt based on cash and cash equivalents, accounts receivable and prepaid expenses, accounts payable and accrued liabilities, long term debt (credit facility) and senior unsecured notes.

Net debt is used by management to provide a more complete understanding of the Company's capital structure and provides a key measure to assess the Company's liquidity. Management has excluded the current and long term financial instrument commodity contracts as they are subject to a high degree of volatility prior to ultimate settlement.

Similarly, management has excluded the current and long term portion of asset retirement obligations as these are estimates based on management's assumptions and subject to volatility based on changes in cast and timing estimates, the risk-free rate and inflation rate.

The following table shows the composition of the non-GAAP measure of net debt with GAAP components from the balance sheet:

($ thousands)	**Year ended December 31, 2018**	Year ended December 31, 2017
Cash and cash equivalents, accounts receivable and prepaid expenses	**(53,334)**	(47,941)
Accounts payable and accrued liabilities	**90,074**	50,725
Long-term debt (credit facility)	**257,395**	125,725
Senior unsecured notes	**215,892**	67,680
Other liabilities	**1,381**	1,747
Net debt	**511,408**	197,936

Critical accounting estimates

Management is required to make judgments, estimates and assumptions that affect the application of accounting policies and the reported amounts of assets, liabilities, income and expenses. Actual results may differ from these estimates. Estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognized in the year in which the estimates are revised and in any future years affected.

The following are critical judgments that management has made in the process of applying accounting policies that have the most significant effect on the financial statements:

(i) Cash generating units

Cash generating units ("CGUs") are defined as the lowest grouping of integrated assets that generate identifiable cash inflows that are largely independent of the cash inflows of other assets or group of assets. The classification of assets into CGUs requires significant judgment and interpretations with respect to the integration between assets, the existence of active markets, external users, shared infrastructures and the way in which management monitors the Company's operations.

(ii) Impairment indicators

Judgments are required to assess when impairment indicators exist and impairment testing is required. In determining the recoverable amount of assets, in the absence of quoted market prices, impairment tests are based on estimates of reserves, production rates, future oil and natural gas prices, future costs, discount rates and other relevant assumptions.

(iii) Exploration and evaluation assets

The application of the Company's accounting policy for exploration and evaluation assets requires management to make certain judgments in determining whether it is likely that future economic benefits exist when activities have not generally reached a stage where technical feasibility and commercial viability can be reasonably determined.

The following are key estimates and their assumptions made by management affecting the measurement of balances and transactions in the financial statements:

(iv) Reserve estimates

Oil and natural gas reserves are used in the calculation of depletion, impairment and impairment reversals. Reserve estimates are based on engineering data, estimated future prices and costs, expected future rates of production and the timing of future capital expenditures, all of which are subject to many uncertainties and interpretations. The Company expects that, over time, its reserve estimates will be revised upward or downward based on updated information such as the results of future drilling, testing and production levels and changes in commodity prices.

(v) Asset retirement obligations

Asset retirement obligations are recognized for the future decommissioning and restoration of property, plant and equipment. These obligations are based on estimated costs, which take into account the anticipated method and extent of restoration and technological advances. Actual costs are uncertain and estimates can vary as a result of changes to relevant laws and regulations, the emergence of new technology, operating experience and prices. The expected timing of future decommissioning and restoration may change due to certain factors, including reserve life. Changes to assumptions related to future expected costs, discount rates and timing may have a material impact on the amounts presented.

(vi) Income taxes

Tax interpretations, regulations and legislation in the various jurisdictions in which the Company and its subsidiaries operate are subject to change. The deferred tax asset or liability is based on estimates as to the timing of the reversal of temporary differences, substantively enacted tax rates and the likelihood of assets being realized.

(vii) Business combinations

Business combinations are accounted for using the acquisition method of accounting when the assets acquired meet the definition of a business combination in accordance with IFRS. The determination of fair value assigned to assets acquired and liabilities assumed requires management to make assumptions and estimates about future events. The assumptions and estimates with respect to determining the fair value of oil and gas properties and E&E assets acquired include estimates of reserves acquired, forecast benchmark commodity prices and discount rates used to present future cash flows. Changes in any of these assumptions or estimates used in determining the fair value of assets acquired and liabilities assumed could impact the amounts assigned to assets, liabilities, goodwill or bargain purchase.

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 15 of the financial statements.

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. 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 pronouncements

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 has reviewed and analyzed contracts that fall into the scope of the new standard. As at January 1, 2019, the Company expects an adjustment for its office lease which will not result in a material impact to the Company's financial results.

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 and annual 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 December 31, 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, condensate 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 risk 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 debt 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, 2018, which will be filed on SEDAR on or before March 30, 2019.

2019 guidance re-affirmed - strong growth and spending within adjusted funds flow

We are pleased to note that our 2019 capital and production budget forecasts annual production per share growth of approximately 13% and fourth quarter 2019 production per share growth of almost 25% as compared to the fourth quarter of 2018. Our production guidance for 2019 is unchanged, with a range of 51,000 to 54,000 Boe/d. First quarter 2019 production guidance is also unchanged with a range of 43,000 to 46,000 Boe/d. The remaining quarters of 2019 are all expected to be well above 50,000 Boe/d, and more specific quarterly guidance will be provided as the year unfolds.

We intend to keep net debt levels relatively flat, with capital spending at or near adjusted funds flow at 2019 price expectations of approximately US$55.00/Bbl WTI oil, US$2.85/MMbtu NYMEX natural gas, C$1.30/GJ AECO natural gas, condensate-WTI differential of US$ -1.00/Bbl,and CAD/USD exchange rate of 1.33. As such, we have set our capital spending for 2019 to a planned range of $300 - $325 million, with flexibility to reduce capital further if pricing unexpectedly falls, while still preserving a healthy growth plan for 2020 if prices remain stable or improve.

NuVista has top quality assets and a management team focused upon relentless improvement. We are excited to continue pursuing our Montney growth plan to 110,000 Boe/d and beyond, and we will adjust the annual pace of growth as needed to ensure balance sheet strength comes first, and that the profitability of that growth is always maximized.