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, 2019. The following MD&A of financial condition and results of operations was prepared at and is dated March 3, 2020. Our December 31, 2019 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, 2020.

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 our financial, commodity, and natural gas risk management strategy and market diversification; expectations that in in 2021, we will arrive at the point where adjusted funds flow will exceed the required capital to maintain production levels at the future minimum volume commitment of 68,000 Boe/d; our flexibility beyond 2021 to moderate growth in order to maximize our free funds flow generating capacity; our expectations that our inventory supports our growth plans; our expectations that we have significant flexibility in our plans beyond 2021; 2020 guidance with respect to production and capital spending; our plans to limit 2020 capital spending to no more than approximately 100 - 110% of adjusted funds flow; our 2020 drilling and infrastructure plans; 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; plans to use free funds flow to reduce debt, buy back shares, or for growth; 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; targeted net debt to annualized current quarter adjusted funds flow; tax pools and future taxability; plans to monitor NuVista's 2020 business plan and to adjust its 2020 budgeted capital program in the context of commodity prices and net debt levels; industry conditions and commodity prices. 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", "free funds flow" 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. Free funds flow is forecast adjusted funds flow less capital expenditures required to maintain production.

Description of business

NuVista is an exploration and production company actively engaged in the development, delineation and production of condensate, natural gas liquids ("NGL"), 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.

Operations activity

	Three months ended December 31		Year ended December 31	
Number of wells	**2019**	2018	**2019**	2018
Wells drilled - gross (net) [1]	**7 (7.0)**	3 (3.0)	**34 (34.0)**	26 (25.5)
Wells completed - gross (net) [2]	**2 (2.0)**	5 (4.8)	**35 (35.0)**	23 (22.5)
Wells brought on production - gross (net) [3]	**7 (7.0)**	0 (0.0)	**39 (38.8)**	19 (18.8)

[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, 2019, NuVista drilled 6.0 (6.0 net) Montney condensate rich natural gas wells and 1 (1.0 net) disposal well compared to 3 (3.0 net) Montney condensate rich natural gas wells in the comparable period of 2018. For the year ended December 31 2019, NuVista drilled 31 (31.0 net) Montney condensate rich natural gas wells, 2 (2.0 net) oil wells and 1 (1.0 net) disposal well, compared to 25 (24.5 net) Montney condensate rich natural gas wells and 1 (1.0 net) disposal well in the comparable period of 2018**.**

All wells in 2019 and 2018 were drilled with a 100% success rate.

Production

	Three months ended December 31			Year ended December 31		
	2019	2018	% Change	**2019**	2018	% Change
Natural gas (Mcf/d)	**204,275**	174,286	17	**182,322**	144,750	26
Condensate & oil (Bbls/d)	**17,195**	14,766	16	**15,170**	12,674	20
NGLs (Bbls/d)	**5,769**	5,246	10	**5,246**	3,554	48
Total (Boe/d)	**57,010**	49,060	16	**50,803**	40,353	26
Condensate, oil & NGLs weighting [1] [2]	**40%**	41%		**40%**	40%	
Condensate & oil weighting [2]	**30%**	30%		**30%**	31%	

[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, 2019 increased 16% and 26% respectively over the comparative periods of 2018 as a result of production increases from continued successful drilling of Montney wells, the incremental production associated with the Pipestone Acquisition, and production associated with the start up of the Pipestone compressor station in late September. Fourth quarter production of 57,010 Boe/d increased 10% from third quarter 2019 production of 51,819 Boe/d, primarily as a result of new wells brought on production in the quarter which offsets declines and unplanned downtime from third party facilities. Condensate & oil volume weighting of 30% in the fourth quarter was consistent with prior year comparative periods.

Pricing

	Three months ended December 31			Year ended December 31		
	2019	2018	% change	**2019**	2018	% change
Realized selling prices [(1),(2)]						
Natural gas ($/Mcf)	**2.74**	3.69	(26)	**2.78**	3.51	(21)
Condensate & oil ($/Bbl)	**62.51**	51.60	21	**64.06**	70.92	(10)
NGLs ($/Bbl)	**11.51**	28.53	(60)	**11.06**	32.83	(66)
Barrel of oil equivalent ($/Boe)	**29.83**	31.69	(6)	**30.26**	37.74	(20)
Benchmark pricing						
Natural gas - AECO 5A daily index (Cdn$/Mcf)	**2.48**	1.56	59	**1.76**	1.50	17
Natural gas - AECO 7A monthly index (Cdn$/Mcf)	**2.34**	1.90	23	**1.62**	1.53	6
Natural gas - NYMEX (monthly) (US$/MMbtu)	**2.50**	3.64	(31)	**2.63**	3.09	(15)
Natural gas - Chicago Citygate (monthly) (US$/MMbtu)	**2.44**	3.62	(33)	**2.56**	3.06	(16)
Natural gas - Dawn (daily) (US$/MMbtu)	**2.24**	3.79	(41)	**2.40**	3.13	(23)
Natural gas - Malin (monthly) (US$/MMbtu)	**2.65**	3.90	(32)	**2.67**	2.69	(1)
Oil - WTI (US$/Bbl)	**56.96**	58.81	(3)	**57.03**	64.77	(12)
Oil - Edmonton Par - (Cdn$/Bbl)	**68.10**	42.79	59	**69.09**	69.39	—
Condensate - Condensate @ Edmonton (Cdn$/Bbl)	**70.03**	59.63	17	**70.11**	78.89	(11)
Condensate - Average C5-WTI differential (US$/Bbl)	**(3.91)**	(13.28)	(71)	**(4.20)**	(3.67)	14
Exchange rate - (Cdn$/US$)	**1.32**	1.32	—	**1.33**	1.30	2

(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.

The WTI benchmark averaged US$56.96/Bbl in the fourth quarter of 2019, 3% below the fourth quarter of last year and slightly above the third quarter of this year which averaged US$56.45/Bbl. In December of 2018, OPEC and other nations agreed to a 1.2 million Bbl/d production cut to stabilize the global oil market. In June 2019 these cuts were extended into 2020 and additional cuts are being contemplated to support the market given the outbreak of the coronavirus. US sanctions against Iran and Venezuela further reduced global oil supply, however offsetting this is continued growth in US production primarily in the Permian basin. Canadian heavy oil differentials widened in a sudden and unprecedented fashion in the fourth quarter of 2018 and this temporarily but significantly pressured the light oil market and also the condensate market. In December of 2018, 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. This curtailment continued throughout the year. The oil supply curtailments have now been extended to the end of 2020 but have been reduced, allowing for additional oil production which has increased demand for condensate. Condensate prices continued to outperform other liquid prices with the Edmonton marker averaging C$70.03/Bbl for the quarter. The oil supply curtailment does not apply to condensate nor to NuVista.

US gas production continued to grow in 2019 but at a slower pace than the previous year. The production growth has been offset by growth in US liquid natural gas ("LNG") exports, gas exports to Mexico, and continued consumption growth in the power and industrial sectors. There are six major LNG projects in the US that are receiving gas already and there will be a number of additional projects coming online in 2020 that will help to provide support for North American gas prices. NYMEX gas prices were up compared to the third quarter of 2019 averaging US$2.50/MMbtu, but a warm start to winter has pressured prices downwards when compared to last winter. Eastern North American and MidWest prices were down relative to NYMEX gas prices in the fourth quarter due to the warm start to winter in those markets. AECO gas prices averaged $2.34/Mcf in the fourth quarter of 2019 representing an increase of 125% from $1.04/Mcf in the third quarter of 2019 and a 23% increase from the fourth quarter of 2018. A significant local storage deficit and a new NGTL Firm Service protocol during system maintenance has improved AECO prices.

Revenue

Petroleum and natural gas revenues

	Three months ended December 31				Year ended December 31			
	2019		2018		**2019**		2018	
($ thousands, except % amounts)	**$**	**% of total**	$	% of total	**$**	**% of total**	$	% of total
Natural gas [(1)]	**51,486**	**33**	59,136	41	**185,200**	**33**	185,170	33
Condensate & oil	**98,884**	**63**	70,103	49	**354,709**	**63**	328,083	59
NGLs [(2)]	**6,109**	**4**	13,767	10	**21,186**	**4**	42,596	8
Total petroleum and natural gas revenues	**156,479**		143,006		**561,095**		555,849	

(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, 2019, our physical delivery sales contracts resulted in a loss of $2.7 million and a gain of $2.6 million respectively (2018 – $1.1 million gain and $18.3 million gain).
(2) Includes butane, propane, ethane and an immaterial amount of sulphur revenue.

For the three months ended December 31, 2019, petroleum and natural gas revenues increased 9% from the comparable period of 2018, due primarily to a 16% increase in production, offset by a 6% decrease in average per Boe realized price for the quarter.

For the year ended December 31, 2019, petroleum and natural gas revenue increased 1% over the comparable period of 2018, due primarily to a 26% increase in production offset by a 20% decrease in realized selling prices.

Condensate & oil volumes averaged 30% of total production in the fourth quarter of 2019, contributing to 63% of total petroleum and natural gas revenues.
A breakdown of natural gas revenue is as follows:

	Three months ended December 31				Year ended December 31			
	2019		2018		**2019**		2018	
($ thousands, except per unit amounts)	**$**	**$/Mcf**	$	$/Mcf	**$**	**$/Mcf**	$	$/Mcf
Natural gas revenue - AECO reference price [(1)]	**44,623**	**2.34**	28,566	1.90	**113,698**	**1.62**	79,439	1.53
Heat/value adjustment [(2)]	**3,549**	**0.20**	2,620	0.17	**9,390**	**0.15**	7,618	0.15
Transportation revenue [(3)]	**7,164**	**0.40**	7,194	0.48	**28,751**	**0.45**	26,467	0.52
Natural gas market diversification revenue (loss)	**(1,138)**	**(0.06)**	19,649	1.07	**30,807**	**0.52**	53,342	0.96
AECO physical delivery sales contract gains (losses) [(4)]	**(2,712)**	**(0.14)**	1,107	0.07	**2,554**	**0.04**	18,304	0.35
Total natural gas revenue	**51,486**	**2.74**	59,136	3.69	**185,200**	**2.78**	185,170	3.51

(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, 2019, natural gas revenue decreased 13% from the comparable period of 2018, due to a 17% increase in production offset by a 26% decrease in realized selling prices. For the year ended December 31, 2019, natural gas revenue remained consistent with the comparable period of 2018, due primarily to a 26% increase in production offset by a 21% 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	
	2019	2018	**2019**	**2018**
AECO physical deliveries	**48%**	35%	**42%**	33%
Dawn physical deliveries	**22%**	26%	**24%**	29%
Malin physical deliveries	**19%**	23%	**21%**	19%
Chicago physical deliveries	**11%**	16%	**13%**	19%

NuVista receives a premium to the AECO spot gas price due to the higher heat content of its natural gas production. Price risk is also mitigated by 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, 2019, the Company delivered 48% of its gas to AECO of which 26% was under AECO physical fixed price delivery sales contracts. NuVista delivered approximately 22% of its natural gas production to Dawn, 19% to Malin, and 11% to Chicago.

NuVista's exposure to AECO floating prices was limited to approximately 22% of volumes in the fourth quarter of 2019 as a result of this market egress, and the inclusion of pre-existing physical and financial delivery sales contracts. 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 2020 and beyond.

Excluding the impact of realized gains (losses) on physical sales contracts, the average selling price for natural gas for the three months and year ended December 31, 2019 was $2.88/Mcf and $2.74/Mcf respectively, compared to $3.62/Mcf and $3.16/Mcf for the comparative periods of 2018, and $2.04/Mcf in the third quarter of 2019.

Condensate & oil revenue

For the three months ended December 31, 2019, condensate & oil revenue increased 41% over the comparable period of 2018 due to a 16% increase in production and a 21% increase in the average realized selling price. For the year ended December 31, 2019, condensate & oil revenue increased 8% over the comparable period of 2018, due primarily to a 20% increase in production, partially offset by a 10% decrease in the average realized selling price.

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 $62.51/Bbl and $64.06/Bbl in the three months and year ended December 31, 2019, an increase of 21% and a decrease of 10% from $51.60/Bbl and $70.92/Bbl for the comparable periods of 2018.

NGL revenue

For the three months ended December 31, 2019, NGL revenue decreased 56% over the comparable period of 2018, due to a 60% decrease in the average realized selling price, partially offset by a 10% increase in production. For the year ended December 31, 2019, NGL revenue decreased 50% over the comparable period of 2018, due primarily to a 66% decrease in the average realized selling price, partially offset by a 48% increase in production.

The NGL contract year typically begins April 1st and ends March 31st of the following year. Western Canadian inventories of propane and butane drew significantly last fall which should lead to stronger prices for both of these products starting April of this year.

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 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 150,000 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 U.S. dollar positions may be hedged to Canadian dollars during the term of the applicable hedge. Foreign currency exposure on interest payments and long-term debt, if there is that exposure, may also be hedged back to Canadian dollars.

	Three months ended December 31					
($ thousands)	**2019**			2018		
	Realized gain (loss)	**Unrealized gain (loss)**	**Total gain (loss)**	Realized gain (loss)	Unrealized gain (loss)	Total gain (loss)
Natural gas	**(127)**	**(30,384)**	**(30,511)**	(6,279)	36,121	29,842
Condensate & oil	**4,083**	**(30,060)**	**(25,977)**	(4,296)	93,917	89,621
Foreign exchange	**—**	**—**	**—**	(108)	(78)	(186)
Gain (loss) on financial derivatives	**3,956**	**(60,444)**	**(56,488)**	(10,683)	129,960	119,277

During the fourth quarter of 2019, the commodity price risk management program resulted in a total loss of $56.5 million, compared to a total gain of $119.3 million for the comparable period of 2018 and a total loss of $6.2 million in the third quarter of 2019. The fair value of financial derivative contracts is 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 unrealized loss in the fourth quarter is primarily as a result of unrealized losses on both natural gas and oil contracts reflective of the narrowing AECO/ NYMEX basis forward strip pricing and increasing WTI forward strip pricing at the end of the quarter compared to the beginning of the quarter. Due to increased volatility in oil and gas prices and the related forward strips pricing, the 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 of 2019 and comparative period of 2018.

($ thousands)	2019			2018		
	Realized gain (loss)	**Unrealized gain (loss)**	**Total gain (loss)**	Realized gain (loss)	Unrealized gain (loss)	Total gain (loss)
Natural gas	**3,086**	**(98,581)**	**(95,495)**	(1,057)	32,122	31,065
Condensate & oil	**14,295**	**(42,582)**	**(28,287)**	(37,224)	61,273	24,049
Foreign exchange	**—**	**—**	**—**	(54)	—	(54)
Gain (loss) on financial derivatives	**17,381**	**(141,163)**	**(123,782)**	(38,335)	93,395	55,060

Year ended December 31

For the year ended December 31, 2019, the commodity price risk management program resulted in a loss of $123.8 million compared to a gain of $55.1 million for the comparable period of 2018.

Nuvista has significant hedges currently in place, with approximately 57% of remaining forecast 2020 condensate & oil production hedged at an average floor price of C$ WTI 77.24/Bbl, and approximately 46% of remaining forecast 2020 natural gas production hedged at an average floor price of $2.01/Mcf.

Price risk management on our physical delivery sale contracts resulted in a loss of $2.7 million and a gain of $2.6 million respectively for the three months and year ended December 31, 2019 compared to gains of $1.1 million and $18.3 million for the comparable periods of 2018.

(a) Financial instruments

The following is a summary of financial derivatives contracts in place as at December 31, 2019:

	WTI fixed price swap	
Term (1)	**Bbls/d**	**Cdn$/Bbl**
2020	6,099	76.28

(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**
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)	—	—	—	—	—	—	—	—
2025	35,000	(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**
2020	51,243	2.68	1,243	2.63

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

Term (1)	Bbls/d	C$ WTI 3 Way Collar Cdn$/Bbl	Cdn$/Bbl	Cdn$/Bbl
2020	4,049	65.62	78.67	85.81

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

Subsequent to December 31, 2019 the Company restructured contracts on 1,600 Bbl/d of the C$WTI 3 Way collars by removing the ceiling in exchange for increasing the sold floor from C$70/Bbl to C$71/Bbl for the February 2020 to December 2020 term.

(b) Physical delivery sales contracts

The Company enters into physical delivery sales contracts to manage commodity price risk. These contracts are not considered to be derivatives and therefore not recorded at fair value. They are considered sales contracts and are recorded at cost at the time of transaction.

The following is a summary of the physical delivery sales contracts in place as at December 31, 2019:

	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
2020	46,339	1.41	1,243	2.62	10,000	(0.26)
2021	—	—	—	—	10,000	(0.26)
2022	—	—	—	—	8,329	(0.26)

(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)	**2019**	2018	**2019**	2018
Gross royalties	**13,336**	8,104	**42,767**	27,691
Gas cost allowance ("GCA")	**(3,768)**	(3,256)	**(15,098)**	(11,418)
Net royalties	**9,568**	4,848	**27,669**	16,273
Gross royalty % excluding physical delivery sales contracts(1)	**8.4**	5.7	**7.7**	5.2
Gross royalty % including physical delivery sales contracts	**8.5**	5.7	**7.6**	5.0
Net royalties $/Boe	**1.82**	1.07	**1.49**	1.10

(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, 2019, gross royalties increased 65% and 54% respectively as compared to the comparable periods of 2018 as a result of the production increases over the prior year. Gross royalties as a percentage of petroleum and natural gas revenues increased as a result of a greater number of wells having fully utilized the royalty incentive programs which carried reduced initial royalty rates.

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, 2019, the 16% and 32% increase in GCA credits received compared to the comparative periods of 2018 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 and gas market diversification activities impact reported average royalty rates as royalties are based on government market reference prices for delivery of product in Alberta and not the Company's average realized prices that include price risk management and gas market diversification activities.

Transportation expenses

	Three months ended December 31		Year ended December 31	
($ thousands, except per unit amounts)	**2019**	2018	**2019**	2018
Natural gas transportation expense	**12,517**	11,830	**48,969**	41,333
Condensate, oil & NGL transportation expense	**2,346**	1,408	**7,364**	3,766
Total transportation expense	**14,863**	13,238	**56,333**	45,099
Natural gas transportation $/Mcf [1]	**0.67**	0.74	**0.74**	0.78
Condensate, oil & NGL transportation $/Bbl	**1.11**	1.04	**0.99**	0.81
Total transportation $/Boe	**2.83**	2.93	**3.04**	3.06

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

For the three months and year ended December 31, 2019, total transportation expenses on a total dollar basis increased from the comparative periods of 2018 due primarily to higher volumes and additional firm commitments for gas transportation and increased trucking of condensate volumes. 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. Fourth quarter total transportation expense increased slightly from third quarter total transportation expense of $14.5 million ($3.03/Boe).

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 trucked volumes. The higher condensate transportation rates for the three months and year ended December 31, 2019 as compared to the prior year comparative periods was primarily as a result of increased condensate production and the trucking of this production from new third party facilities in 2019. Construction of third party liquid pipelines at these facilities is ongoing, with scheduled completion in the first quarter of 2020.

Operating expenses

	Three months ended December 31		Year ended December 31	
($ thousands, except per unit amounts)	**2019**	2018	**2019**	2018
Operating expenses	**50,528**	40,886	**178,275**	143,603
Per Boe	**9.63**	9.06	**9.61**	9.75

For the three months and year ended December 31, 2019, operating expenses increased 24% as a result of the increased production compared to the prior year comparative periods of 2018. The per Boe costs decreased slightly on the prior year to date comparative period due to increased production, operational efficiencies, high utilization of the Elmworth and Bilbo compressor stations and the integration of the acquired Pipestone assets. Compared to third quarter operating expenses of $47.5 million ($9.97/Boe), fourth quarter operating expenses per Boe decreased primarily due to the incremental production increases in Pipestone leading to higher efficiency and facility utilization.

In accordance with the adoption of IFRS 16 - *Leases* on January 1, 2019 as disclosed in Note 3 to the financial statements, base rent for the Company's field office is recognized as a lease beginning January 1, 2019. This has resulted in base rent costs in the amount of $127.0 thousand in the year ended December 31, 2019 being excluded from operating expenses, as the costs are now accounted for under the new lease standard.

The minimum take or pay commitments associated with the gas processing lease and gas transportation lease identified in the third quarter of 2019 is excluded from operating expense and classified as a lease under IFRS 16.

For the year ended December 31, 2019, total payments under these two new leases of $3.4 million were excluded from operating expenses and accounted for under the new lease standard.

General and administrative expenses ("G&A")

	Three months ended December 31		Year ended December 31	
($ thousands, except per Boe amounts)	**2019**	2018	**2019**	2018
Gross G&A expenses	**5,749**	5,768	**23,976**	23,358
Overhead recoveries	**(372)**	(497)	**(1,794)**	(934)
Capitalized G&A	**(897)**	(1,191)	**(5,330)**	(4,884)
Net G&A expenses	**4,480**	4,080	**16,852**	17,540
Gross G&A per Boe	**1.10**	1.28	**1.29**	1.59
Net G&A per Boe	**0.85**	0.90	**0.91**	1.19

For the three months and year ended December 31, 2019, gross G&A expenses have remained consistent with the prior comparative quarter, but increased slightly from the prior year comparative period, consistent with increasing company size and activity. As a result of continued production increases and efficiencies gained from an operational focus on Wapiti Montney and continued focus on cost control, NuVista has continued to drive G&A costs per Boe downwards.

The Company's policy of allocating and capitalizing G&A expenses associated with new capital projects remained unchanged in 2018 and 2019. Overhead recoveries have increased since the Pipestone Acquisition due to NuVista's ownership interest and operatorship of the Wembley gas plant. G&A capitalized and operating recoveries are in accordance with industry practice.

In accordance with the adoption of IFRS 16 - *Leases* on January 1, 2019 as disclosed in Note 3 to the financial statements, base rent for the Company's head office expense is recognized as a lease prospective January 1, 2019. This has resulted in base rent costs in the amount of $0.7 million in the year ended December 31, 2019 being excluded from gross G&A expenses, as the costs are now accounted for under the new lease standard.

Share-based compensation expense

	Three months ended December 31		Year ended December 31	
($ thousands)	**2019**	2018	**2019**	2018
Stock options	**814**	919	**3,679**	3,515
Director deferred share units	**720**	(725)	**478**	(366)
Restricted share awards	**335**	414	**1,422**	1,668
Performance share awards	**202**	97	**621**	225
Total	**2,071**	705	**6,200**	5,042

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.

The increase in share-based compensation for the three months and year ended December 31, 2019 over the prior year comparative periods was primarily due to the change in the valuation of the DSU liability and related DSU expense. For the year ended December 31, 2019, the increase in DSU expense recognized on DSUs granted in the year more than offset the decrease in DSU liability as a result of the decrease in share price from $4.08/share at December 31, 2018 to $3.19/share at December 31, 2019.

Transaction costs

	Three months ended December 31		Year ended December 31	
($ thousands, except per Boe amounts)	**2019**	2018	**2019**	2018
Total transaction costs	**—**	—	**—**	2,624
Total transaction costs per Boe	**—**	—	**—**	0.18

Transaction costs are 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)	**2019**	2018	**2019**	2018
Interest on long-term debt (credit facility)	**3,801**	2,548	**14,208**	5,509
Interest on senior unsecured notes [1]	**3,813**	3,813	**15,179**	16,222
Call premium on redemption of 2021 Notes	**—**	—	**—**	6,562
Interest expense	**7,614**	6,361	**29,387**	28,293
Lease interest expense	**2,582**	—	**3,631**	—
Accretion expense	**612**	540	**2,070**	1,776
Total financing costs	**10,808**	6,901	**35,088**	30,069
Interest expense per Boe	**1.45**	1.41	**1.58**	1.92
Total financing costs per Boe	**2.06**	1.53	**1.89**	2.04

(1) 2018 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, 2019, interest expense on long-term debt increased from the comparable periods in 2018 due to higher average bank indebtedness and interest rates throughout the period. Average interest rates on long-term debt for the three months and year ended December 31, 2019 were 3.9% and 3.8% compared to average interest rates of 3.5% and 3.3% for the comparative periods of 2018. Interest rates have increased in 2019 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, 2019, 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 Notes at December 31, 2019 is $216.8 million.

Lease interest expense for the three months and year ended December 31, 2019 is from the adoption of IFRS 16 - *Leases* on January 1, 2019 as disclosed in Note 3 to the financial statements. The weighted average incremental borrowing rate on the office lease liabilities is 6%. Two new leases were identified in the third quarter of 2019 for gas processing and transportation associated with the start up of the Pipestone compressor and pipeline connecting the compressor to the SemCAMS Wapiti plant. The weighted average incremental borrowing rates on these new lease liabilities are 8% and 11% respectively.

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, 2019 and 2018:

	Three months ended December 31			
		2019		2018
($ thousands, except per Boe amounts)	**$**	**$/Boe**	$	$/Boe
Petroleum and natural gas revenues (1)	**156,479**	**29.83**	143,006	31.69
Realized gain (loss) on financial derivatives	**3,956**	**0.75**	(10,683)	(2.37)
	160,435	**30.58**	132,323	29.32
Royalties	**(9,568)**	**(1.82)**	(4,848)	(1.07)
Transportation expense	**(14,863)**	**(2.83)**	(13,238)	(2.93)
Operating expense	**(50,528)**	**(9.63)**	(40,886)	(9.06)
Operating netback (2)	**85,476**	**16.30**	73,351	16.26
General and administrative expense	**(4,480)**	**(0.85)**	(4,080)	(0.90)
Deferred share units recovery (expense)	**(720)**	**(0.14)**	725	0.16
Interest and lease finance expense	**(10,196)**	**(1.94)**	(6,361)	(1.41)
Corporate netback (2)	**70,080**	**13.37**	63,635	14.11

(1) Includes price risk management losses of $2.7 million (2018 - $1.1 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			
		2019		2018
($ thousands, except per Boe amounts)	**$**	**$/Boe**	$	$/Boe
Petroleum and natural gas revenues (1)	**561,095**	**30.26**	555,849	37.74
Realized gain (loss) on financial derivatives	**17,381**	**0.94**	(38,335)	(2.60)
	578,476	**31.20**	517,514	35.14
Royalties	**(27,669)**	**(1.49)**	(16,273)	(1.10)
Transportation expense	**(56,333)**	**(3.04)**	(45,099)	(3.06)
Operating expense	**(178,275)**	**(9.61)**	(143,603)	(9.75)
Operating netback (2)	**316,199**	**17.06**	312,539	21.23
General and administrative	**(16,852)**	**(0.91)**	(17,540)	(1.19)
Deferred share units recovery (expense)	**(478)**	**(0.03)**	366	0.02
Interest expense	**(33,018)**	**(1.78)**	(28,293)	(1.92)
Transaction costs	**—**	**—**	(2,624)	(0.18)
Corporate netback (2)	**265,851**	**14.34**	264,448	17.96

(1) Includes price risk management gains of $2.6 million (2018 - $18.3 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)	**2019**	2018	**2019**	2018
Cash flow from operating activities	**80,321**	70,447	**263,856**	251,057
Per share, basic	**0.36**	0.31	**1.17**	1.32
Per share, diluted	**0.36**	0.31	**1.17**	1.31
Adjusted funds flow [(1)]	**70,080**	63,635	**265,851**	264,448
Per share, basic	**0.31**	0.28	**1.18**	1.39
Per share, diluted	**0.31**	0.28	**1.18**	1.38

(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 and year ended December 31, 2019, cash flow from operating activities of $80.3 million and $263.9 million respectively, increased 14% and 5% from the prior year comparative periods, primarily due to increased petroleum and natural gas revenues as a result of increased production and realized gains on financial derivatives compared to realized losses in the prior year comparative periods, offset by higher royalties, transportation and operating expenses as a result of increased production.

Adjusted funds flow for the three months ended December 31, 2019 and the comparable period of 2018 was $70.1 million ($0.31/share, basic) and $63.6 million ($0.28/share, basic) respectively, $10.2 million and $6.8 million lower than cash flow from operating activities in the comparable period, due to changes in asset retirement expenditures and non-cash working capital.

Adjusted funds flow for the year ended December 31, 2019 and 2018 was 265.9 million ($1.18/share, basic) and $264.4 million ($1.39 /share, basic) respectively, $2.0 million and $13.4 million higher than cash flow from operating activities in the comparable period, 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)	**2019**	2018	**2019**	2018
Depletion of condensate, oil and natural gas assets	**43,067**	42,740	**199,638**	142,270
Depreciation of fixed assets	**4,253**	3,716	**16,527**	13,810
Depreciation of right-of-use assets	**2,085**	—	**3,309**	—
DD&A expense	**49,405**	46,456	**219,474**	156,080
DD&A rate per Boe	**9.42**	10.29	**11.84**	10.60

DD&A expense for three months and year ended December 31, 2019 was $49.4 million ($9.42/Boe) and $219.5 million ($11.84/Boe) compared to $46.5 million ($10.29/Boe) and $156.1 million ($10.60/Boe) for the comparable periods of 2018, and $49.6 million ($10.41/Boe) in the third quarter of 2019. DD&A expense for the three months and year ended December 31, 2019 includes a negative charge to Q4 depletion in the amount of ($1.7 million) ($0.33/Boe) and a year to date charge of $34.6 million ($1.86/Boe) respectively, related to changes in estimates and the impact of the change in discount rate on asset retirement obligations for wells with no remaining reserves that were previously fully depleted. The full amount of this asset retirement obligation liability change is included in depletion expense.

The Wapiti Montney CGU DD&A rate per Boe for the three months and year ended December 31, 2019 decreased to $9.23/Boe and $9.73/Boe compared to $9.62/Boe and $10.12/Boe for the comparable periods of 2018, and $9.91/

Boe in the third quarter of 2019. These improved DD&A rates are a result of continued successful development and favorable finding and development costs.

Depreciation of right-of-use assets is the depreciation of assets recognized for the Company's head office lease in Calgary and the field office lease in Grande Prairie starting on January 1, 2019, with the adoption of IFRS 16 - *Leases* as disclosed in Note 3 of the financial statements, and the addition of the gas processing and transportation leases added in the third quarter. Depreciation on right-of-use assets is recorded on a straight line basis over the term of the lease.

At December 31, 2019 there were indicators of impairment identified in NuVista's Wapiti Montney CGU as a result of sustained declines in the forward commodity prices for condensate, oil and natural gas and a reduction in market capitalization. An impairment test was performed on property, plant and equipment assets. For the December 31, 2019 test, property, plant and equipment was assessed based on the recoverable amount estimated using a value in use calculation based on expected future cash flows generated from proved and probable reserves using pre-tax discount rates ranging from 10% to 17%, based on the independent external reserves report. No impairment was recognized at December 31, 2019, as the estimated recoverable amount of the Wapiti Montney CGU exceeded its respective carrying value.

During the year ended 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.

Exploration and evaluation ("E&E") expense

	Three months ended December 31		Year ended December 31	
($ thousands, except per Boe amounts)	**2019**	2018	**2019**	2018
Exploration and evaluation expense	**—**	921	**3,668**	2,710
Per Boe	**—**	0.20	**0.20**	0.18

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, 2019**	December 31, 2018
Balance, January 1	**102,703**	72,430
Accretion expense	**2,070**	1,776
Liabilities acquired	**—**	11,141
Change in discount rate, Pipestone Acquisition	**—**	17,571
Liabilities incurred	**3,831**	3,291
Liabilities disposed	**(888)**	(14)
Change in estimates	**36,194**	5,791
Change in discount rate	**(4,994)**	4,175
Liabilities settled	**(14,383)**	(13,458)
Balance, end of period	**124,533**	102,703
Expected to be incurred within one year	**11,575**	12,500
Expected to be incurred beyond one year	**112,958**	90,203

Asset retirement obligations ("ARO") are based on estimated costs to reclaim and abandon ownership interests in condensate, oil and natural gas assets including well sites, gathering systems and processing facilities. At December 31, 2019, NuVista had an ARO balance of $124.5 million as compared to $102.7 million as at December 31, 2018. The Bank of Canada's long-term risk-free bond rate of 1.8% (December 31, 2018 – 2.2%) and an inflation rate of 1.4% (December 31, 2018 – 2.0%) were used to calculate the net present value of the asset retirement obligations. At December 31, 2019, the estimated total undiscounted and uninflated amount of cash required to settle NuVista's ARO was $133.8 million (December 31, 2018 – $106.0 million) with an estimated 40% to be incurred within the next 10 years. Actual ARO expenditures for the year ended December 31, 2019 were $14.4 million compared to $13.5 million for the year ended December 31, 2018.

The ARO liability was decreased by $5.0 million as a result of a decrease in the discount rate from December 31, 2018. The Company was very active in the first quarter of 2019 in abandonment and reclamation activities, with $12.7 million of the $14.4 million year to date expenditures incurred during the first quarter. The Company has recognized a change in estimate resulting in an increase to the ARO liability in the amount of $36.2 million, primarily as a result of higher costs incurred on some of the abandonment projects in the first quarter and increases in abandonment cost estimates for certain wells in our northwest Alberta area. This change in estimate was included in DD&A expense as there are no reserves booked in these areas where the ARO change took place.

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.

Other receivable

The Company has entered into contracts for the construction of two Pipestone compressor stations, which secured third party ownership and funding of the assets. The other receivable balance of $10.3 million represents expenses incurred that have not yet been reimbursed related to these assets.

Capital expenditures

	Three months ended December 31				Year ended December 31			
($ thousands, except % amounts)	**2019**	**% of total**	2018	% of total	**2019**	**% of total**	2018	% of total
Land and retention costs	**151**	**—**	(78)	—	**1,133**	**—**	1,801	1
Geological and geophysical	**1,224**	**3**	1,392	2	**7,961**	**3**	6,415	2
Drilling and completion	**44,204**	**84**	50,532	65	**239,441**	**79**	257,626	76
Facilities and equipment	**7,054**	**13**	25,586	33	**52,801**	**18**	74,512	22
Corporate and other	**181**	**—**	1	—	**486**	**—**	438	—
Capital expenditures (1)	**52,814**		77,433		**301,822**		340,792	

(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 three months and year ended December 31, 2019 were $52.8 million and $301.8 million respectively. Included in facilities and equipment in the year ended December 31, 2019 is a credit of $14.2 million for costs incurred in 2018 that have been reclassified to other receivable. The Company focused the majority of its fourth quarter exploration and development expenditures on drilling activities.

Of the $301.8 million capital spent to date in 2019, $296.6 million was classified as property, plant and equipment additions, and $5.2 million was classified as exploration and evaluation asset additions.

Right-of-use assets and lease liabilities

In accordance with the adoption of IFRS 16 - *Leases*, on January 1, 2019, the Company recognized right-of-use assets and lease liabilities for our head and field office leases. In the three months ending September 30, 2019, the Company recognized a gas processing lease associated with the start up of the Pipestone compressor, and a gas transportation lease associated with the pipeline that connects the Pipestone compressor to the SemCAMS Wapiti plant. At December 31, 2019, the total right-of-use asset is $116.6 million and the total lease liability is $119.3 million, of which $3.4 million is classified as a current liability.

Deferred income taxes

For the three months and year ended December 31, 2019, the Company recorded tax recoveries of $10.9 million and $39.2 million respectively, compared to expenses of $40.2 million and $55.5 million in the comparable periods of 2018.

The deferred income tax recovery in the year ended December 31, 2019 incorporates the Alberta corporate income tax rate reduction introduced in the second quarter of 2019, being reduced 1% per year from 2019 to 2022, which results in the Alberta corporate income tax rate reduction from 12% to 8%.

Tax pools

At December 31, 2019, NuVista had approximately $1.7 billion (2018 – $1.6 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)	**2019**	%
Canadian exploration expense	**263**	100%
Canadian development expense	**430**	30-45% declining balance
Canadian oil and natural gas property expense	**292**	10-15% declining balance
Undepreciated capital cost	**262**	25-37.5% declining balance
Non-capital losses	**398**	100%
Other	**19**	various rates
Total federal tax pools	**1,664**	
Additional Alberta tax pools	**10**	100%

Net earnings (loss)

	Three months ended December 31		Year ended December 31	
($ thousands, except per share amounts)	**2019**	2018	**2019**	2018
Net earnings (loss)	**(29,557)**	104,086	**(63,833)**	136,245
Per share - basic	**(0.13)**	0.46	**(0.28)**	0.71
Per share - diluted	**(0.13)**	0.46	**(0.28)**	0.71

For the three months ended December 31, 2019 the net loss compared to the prior year comparative period net earnings is primarily a result of a $190.4 million increase in the unrealized hedging loss and increased DD&A, offset by increased adjusted funds flow and an increase in the deferred income tax recovery.

For the year ended December 31, 2019, the net loss compared to the prior year comparative period net earnings is primarily as a result of a $234.6 million increase in the unrealized hedging loss and increased DD&A, offset by increased adjusted funds flow and an increase in the deferred income tax recovery.

The net earnings (loss) reported is significantly impacted by unrealized gains (losses) on financial derivatives recognized at each period end as a result of the market to market values or fair value of financial derivative contracts in place at each period end. Net earnings before taxes and excluding unrealized gains (losses) on financial derivatives was $20.0 million for the three months ended December 31, 2019 and $14.3 million for the prior year comparative period. Net earnings before taxes and excluding unrealized gain (loss) on financial derivatives was $38.1 million for the year ended December 31, 2019 and $98.3 million for the prior year comparative period. The unrealized market to market values are a function of highly volatile commodity prices, resulting in significant variances in the values from quarter to quarter. The financial derivatives contracts are in place to provide greater adjusted funds flow stability and certainty. Over the past five years, NuVista has a cumulative realized gain on financial derivatives in the amount of $53.2 million.

Liquidity and capital resources

Long-term debt (credit facility)

At December 31, 2019, the Company had a $550 million (December 31, 2018 - $450 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 properties and equipment. The credit facility has a tenor of two years 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, 2019, NuVista was in compliance with all covenants. The semi annual review was completed in the fourth quarter which resulted with an increase to the credit facility of $50 million. The next review is scheduled for on or before April 30, 2020. Upon successful renewal, the tenor of the credit facility will extend to April 2022.

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. 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 interest expense in 2018, for a total incremental expense on payout of $8.8 million.

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

($ thousands)	**December 31, 2019**	December 31, 2018
Basic common shares outstanding	**225,592**	225,306
Share price(1)	**3.19**	4.08
Total market capitalization	**719,638**	919,248
Cash and cash equivalents, accounts receivable and prepaid expenses	**(62,772)**	(53,334)
Other receivable	**(10,301)**	—
Accounts payable and accrued liabilities	**110,144**	90,074
Long-term debt (credit facility)	**306,274**	257,395
Senior unsecured notes	**216,771**	215,892
Other liabilities	**1,859**	1,381
Net debt (2)	**561,975**	511,408
Annualized current quarter adjusted funds flow	**280,320**	254,540
Net debt to annualized current quarter adjusted funds flow	**2.0**	2.0
Adjusted funds flow	**265,851**	264,448
Net debt to adjusted funds flow	**2.1**	1.9

(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, 2019, net debt was $562.0 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, 2019, NuVista had drawn $306.3 million on its long-term debt (credit facility) and had outstanding letters of credit of $8.0 million which reduce the credit available on the credit facility, leaving $235.8 million of unused credit facility capacity based on the committed credit facility of $550.0 million.

NuVista plans to monitor its 2020 business plan and adjust its 2020 budgeted capital program of $300 - $330 million in the context of commodity prices and net debt levels.

As at December 31, 2019, there were 225.6 million common shares outstanding. In addition, there were 7.7 million stock options with an average exercise price of $5.76 per option, 1.0 million RSAs, and 1.0 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, 2019:

($ thousands)	**Total**	2020	2021	2022	2023	2024	Thereafter
Transportation(1)	**948,246**	81,628	109,371	106,565	88,083	81,303	481,296
Processing (1)	**1,065,201**	55,674	77,057	91,175	91,759	89,686	659,850
Office lease (2)	**6,046**	876	938	948	999	857	1,428
Total commitments (3)	**2,019,493**	138,178	187,366	198,688	180,841	171,846	1,142,574

(1) Certain of the transportation and processing commitments are secured by outstanding letters of credit of $7.3 million at December 31, 2019 (December 31, 2018 - $7.3 million).

(2) Represents the undiscounted future commitments of variable operating expenses related to the Company's office leases.

(3) Excludes commitments recognized within lease liabilities.

Off "balance sheet" arrangements

NuVista has certain commitments which are reflected in the contractual obligations and commitments table, which were entered into in the normal course of operations. Most transportation and processing commitments have been treated as operating leases whereby the payments are included in operating or transportation expenses.

Annual financial information

The following table highlights selected annual financial information for the years ended December 31, 2019, 2018 and 2017:

($ thousands, except per share amounts)	**2019**	2018	2017
Petroleum and natural gas revenues	**561,095**	555,849	377,746
Net earnings (loss)	**(63,833)**	136,245	94,638
Per basic and diluted share	**(0.28)**	0.71	0.54
Balance sheet information			
Total assets	**2,331,361**	2,180,874	1,186,419
Long-term debt	**306,274**	257,395	125,725
Senior unsecured notes	**216,771**	215,892	67,680
Shareholders' equity	**1,348,756**	1,405,017	863,579

Quarterly financial information

The following table highlights NuVista's performance for the eight quarterly reporting periods from March 31, 2018 to December 31, 2019:

($ thousands, except	**2019**				**2018**			
per share amounts)	**Dec 31**	Sep 30	Jun 30	Mar 31	Dec 31	Sep 30	Jun 30	Mar 31
Production (Boe/d)	**57,010**	51,819	50,391	43,839	49,060	40,080	36,035	36,099
Petroleum and natural gas revenues	**156,479**	132,801	137,752	134,064	143,006	150,956	137,131	124,756
Net earnings (loss)	**(29,557)**	(7,650)	9,301	(35,927)	104,086	3,467	6,322	22,371
Per basic share	**(0.13)**	(0.03)	0.04	(0.16)	0.46	0.02	0.04	0.13
Cash flow from operating activities	**80,321**	48,998	81,235	53,302	70,447	51,740	63,576	65,294
Per basic share	**0.36**	0.22	0.36	0.24	0.31	0.28	0.36	0.38
Adjusted funds flow (1)	**70,080**	59,799	64,318	71,654	63,635	72,610	69,472	58,732
Per basic share	**0.31**	0.27	0.29	0.32	0.28	0.39	0.40	0.34

(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, asset acquisitions and the construction of a compressor station in that core area. Production from Wapiti Montney in 2019 is 95% of total production. Over the prior eight quarters, quarterly revenue has been in a range of $124.8 million to $156.5 million with revenue primarily influenced by production volumes and commodity prices. Net earnings (losses) have been in a range of a net loss of $35.9 million to net earnings of $104.1 million with earnings primarily influenced by realized and unrealized gains and losses on financial derivatives, commodity prices, impairments, production volumes, 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 18 "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)	**2019**	2018	**2019**	2018
Cash provided by (used in) operating activities	**80,321**	70,447	**263,856**	251,057
Add back:				
Asset retirement expenditures	**712**	2,835	**14,383**	13,458
Change in non-cash working capital [1]	**(10,953)**	(9,647)	**(12,388)**	(67)
Adjusted funds flow	**70,080**	63,635	**265,851**	264,448
Adjusted funds flow per share, basic	**0.31**	0.28	**1.18**	1.39
Adjusted funds flow per share, diluted	**0.31**	0.28	**1.18**	1.38

[1] Refer to Note 19 "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, interest and lease finance expense. Netbacks per Boe are calculated by dividing the netbacks by total production volumes sold in the period.

NuVista adopted IFRS 16 - *Leases* using the modified retrospective approach, whereby the cumulative effect of initially applying the standard was recognized as an increase to right-of-use assets with a corresponding increase to lease liabilities, with no impact to opening retained earnings. Prior year comparative information has not been restated.

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 earnings (loss) for the period:

	Three months ended December 31		Year ended December 31	
($ thousands)	**2019**	2018	**2019**	2018
Net earnings (loss) and comprehensive income (loss)	**(29,557)**	104,086	**(63,833)**	136,245
Add back:				
Depletion, depreciation, amortization and impairment	**49,405**	46,456	**219,474**	156,080
Exploration and evaluation	**—**	921	**3,668**	2,710
Loss (gain) on property dispositions	**(1,241)**	—	**(3,175)**	146
Share-based compensation	**2,071**	705	**6,200**	5,042
Unrealized loss (gain) on financial derivatives	**60,444**	(129,960)	**141,163**	(93,395)
Deferred income tax expense (recovery)	**(10,934)**	40,162	**(39,238)**	55,478
General and administrative expenses	**4,480**	4,080	**16,852**	17,540
Transaction costs	**—**	—	**—**	2,624
Financing costs	**10,808**	6,901	**35,088**	30,069
Operating netback	**85,476**	73,351	**316,199**	312,539
Deduct:				
General and administrative expenses	**(4,480)**	(4,080)	**(16,852)**	(17,540)
Deferred share units recovery (expense)	**(720)**	725	**(478)**	366
Interest and lease finance expense	**(10,196)**	(6,361)	**(33,018)**	(28,293)
Transaction costs	**—**	—	**—**	(2,624)
Corporate netback	**70,080**	63,635	**265,851**	264,448

Capital expenditures

Capital expenditures are equal to cash flow used in investing activities, excluding changes in non-cash working capital and other receivable. Any expenditures on the other receivable are being refunded to NuVista and are therefore included under current assets. 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:

	Three months ended December 31		Year ended December 31	
($ thousands)	**2019**	2018	**2019**	2018
Cash flow used in investing activities	**(29,097)**	(50,428)	**(312,156)**	(925,963)
Changes in non-cash working capital	**(12,498)**	(28,684)	**365**	(34,273)
Property acquisitions	**—**	1,679	**—**	619,444
Other receivable	**(10,901)**	—	**10,301**	—
Property dispositions	**(318)**	—	**(332)**	—
Capital expenditures	**(52,814)**	(77,433)	**(301,822)**	(340,792)

Net debt

NuVista has calculated net debt based on cash and cash equivalents, accounts receivable and prepaid expenses, accounts payable and accrued liabilities, other receivable, 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 cost 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)	**December 31, 2019**	December 31, 2018
Cash and cash equivalents, accounts receivable and prepaid expenses	**(62,772)**	(53,334)
Other receivable	**(10,301)**	—
Accounts payable and accrued liabilities	**110,144**	90,074
Long-term debt (credit facility)	**306,274**	257,395
Senior unsecured notes	**216,771**	215,892
Other liabilities	**1,859**	1,381
Net debt	**561,975**	511,408

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

Condensate 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 condensate 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

Leases

NuVista adopted IFRS 16 - *Leases* ("IFRS 16") on January 1, 2019. IFRS 16 introduces a single recognition and measurement model for leases which requires a right-of-use asset and lease liability to be recognized on the balance sheet for contracts that are, or contain, a lease.

NuVista adopted IFRS 16 using the modified retrospective approach, whereby the cumulative effect of initially applying the standard was recognized as an increase to right-of-use assets with a corresponding increase to lease liabilities.

On adoption of IFRS 16, the Company has recognized lease liabilities in relation to all lease arrangements measured at the present value of the remaining lease payments from commitments disclosed as at December 31, 2018, adjusted by commitments in relation to arrangements not containing leases, short-term and low-value leases, and discounted using the Company's incremental borrowing rate as of January 1, 2019. The associated right-of-use assets were measured at the amount equal to the lease liability on January 1, 2019, with no impact on retained earnings. The weighted average incremental borrowing rate used to determine the lease liability at adoption was 6%. The right-of-use assets and lease liabilities recognized relate to the Company's head office lease in Calgary, and the field office lease in Grande Prairie.

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 and year ended December 31, 2019, 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;
- Labour risk related to availability, productivity and retention of qualified personnel;
- Widening concerns over climate change, fossil fuel consumption, green house gas emissions, and water and land use could lead governments to enact additional laws, regulations and costs or taxes that may be applicable to NuVista; and
- Changes to environmental regulations related to climate change could impact the demand for, development of or quality of NuVista's petroleum products, or could require increased capital expenditures, operating expenses, asset retirement obligations and costs, which could result in increased costs which would reduce the profitability and competitiveness of NuVista if commodity prices do not rise commensurate with the increased costs. In addition, such regulatory changes could necessitate NuVista to develop or adapt new technologies, possibly requiring significant investments of capital.

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, 2019, which will be filed on SEDAR on or before March 30, 2019.

Environmental, Social, Governance ("ESG") - progress continues

We are proud to have demonstrated our commitment to transparency and ethical practices in our inaugural Environmental, Social, and Governance ("ESG") report earlier in 2019. This report, available for viewing on NuVista's website, provides a comprehensive look at NuVista's ESG practices while highlighting the proactivity and excellent execution our teams have always demonstrated in advancement of our ESG performance. Key highlights of the report include our high safety and environmental performance, our long term progress in reducing GHG intensity, and our strong governance and community focus. Approximately 70% of our current production is comprised of natural gas which has the lowest carbon footprint of any hydrocarbon, leading to our GHG performance being well below the North American benchmark. We continue to execute projects to enhance our ESG progress, and we look forward to providing updated ESG reporting in the future.

In addition, we are pleased to announce recent changes to our Board committees in light of our increased focus on ESG initiatives. We have established an ESG Committee, the members of which are: Mr. Sheldon Steeves (Chair), Mr. Brian Shaw, Ms. Debbie Stein and Mr. Grant Zawalsky.

2020 guidance re-affirmed, but monitoring commodity price pressure

NuVista is pleased to provide an update on our 2020 plans in light of the extreme volatility in the current commodity markets. The primary governor on our annual plan will remain as always to maintain the balance between capital spending and adjusted funds flow in order to protect the balance sheet first. This then allows us to grow production volumes at a comfortable pace commensurate with the flexibility in our future volume commitments.

Our 2020 guidance range is for production of 57,000 Boe/d with capital spending of $300 million, and up to 61,000 Boe/d with capital spending of $330 million, representing over 15% annual growth at midpoint. Although the WTI oil benchmark price has suffered a steep decline recently, our strong current hedge position and improved condensate differentials dampen the impact of pricing volatility. We expect that if current prices prevail,our projected capital spending would need to be adjusted to the bottom of the aforementioned range to ensure it remains within +/-10% of adjusted funds flow. If prices continue to deteriorate, we can use our significant development plan flexibility to reduce capital spending further. In this case, we do not anticipate that 2020 production would be suppressed below 57,000 Boe/d since late-year capital spending contributes little to current year production.

As anticipated, we expect capital spending of $200 million in the first half of 2020. Due to favorable weather, two pads in Elmworth and Gold Creek will be completed by the end of March instead of April, bringing projected first quarter spending up to $150 million, and second quarter down to $50 million. We will monitor pricing and adjusted funds flow and will provide a spending plan update in the spring. This will in part be based upon the performance and phasing of the 15 wells which are expected to come online prior to the end of the second quarter. We believe it is prudent to maintain the winter drilling season unchanged while monitoring commodity price changes, with any potential adjustments to capital spending to take effect after spring breakup. We will revisit our capital guidance at that time to ensure financial flexibility remains intact, incurring little to no incremental debt during the year.

As previously communicated, we expect the third party downtime issues which are affecting production in the first quarter, to gradually improve towards the spring. In addition, we have been required to temporarily shut in certain producing wells for fracture treatments on adjacent newly drilled wells in Pipestone and other areas. As a result, the first quarter is expected to average in the range of 50,000 - 54,000 Boe/d and the second quarter in the range of 58,000 - 62,000 Boe/d. These figures are unchanged as compared to previous guidance.