Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations

The MD&A is intended to provide a narrative description of Encana's business from management's perspective. This MD&A should be read in conjunction with the audited Consolidated Financial Statements and accompanying notes for the period ended December 31, 2018 ("Consolidated Financial Statements"), which are included in Item 8 of this Annual Report on Form 10-K. Common industry terms and abbreviations are used throughout this MD&A and are defined in the Definitions, Conversions and Conventions sections of this Annual Report on Form 10-K. This MD&A includes the following sections:

Executive Overview

Strategy

By executing on its strategy as outlined in Items 1 and 2 of this Annual Report on Form 10-K, Encana focuses on quality cash flow growth from high margin, scalable, top tier assets located in some of the best plays in North America, referred to as the "Core Assets". As at December 31, 2018, these comprised Montney and Duvernay in Canada and Eagle Ford and Permian in the U.S. These top tier assets form a multi-basin portfolio of oil, NGL and natural gas producing plays enabling flexible and efficient investment of capital into high margin liquids plays that support sustainable cash flow generation for the Company. Encana rapidly deploys successful ideas and practices across its top tier assets, becoming more efficient as innovative and sustainable technical improvements are implemented.

In executing its strategy, Encana focuses on its core values of One, Agile and Driven, which guide the organization to be flexible, responsive, determined and motivated with a commitment to excellence and a passion to succeed as a unified team.

In evaluating its operations and assessing its leverage, the Company reviews performance-based measures such as Non-GAAP Cash Flow and Non-GAAP Cash Flow Margin and debt-based metrics such as Debt to Adjusted Capitalization and Net Debt to Adjusted EBITDA, which are non-GAAP measures and do not have any standardized meaning under U.S. GAAP. These measures may not be similar to measures presented by other issuers and should not be viewed as a substitute for measures reported under U.S. GAAP. Further information regarding these measures, including reconciliations to the closest GAAP measure, can be found in the Non-GAAP Measures section of this MD&A.

Highlights

During 2018, Encana met all of the targets set in its full year 2018 guidance by successfully executing the Company's 2018 capital plan, maintaining operational efficiencies achieved in 2017 and minimizing the effect of inflationary costs. Higher revenues in 2018 compared to 2017 resulted from higher liquids benchmark prices and production volumes. Higher oil and NGL benchmark prices contributed to increases in Encana's average realized oil and NGL prices of 30 percent and 15 percent, respectively. Liquids production volumes increased by 30 percent compared to 2017 and represented approximately 47 percent of total production volumes in 2018. Encana also focused on the diversification of the Company's downstream markets to capture higher realized prices. Encana remains committed to delivering a business model that allows the Company to adapt to fluctuating commodity prices.

Significant Developments

- Announced a definitive merger agreement on November 1, 2018 to acquire all of the issued and outstanding shares of common stock of Newfield in an all stock-transaction. The acquisition closed on February 13, 2019, adding to Encana's portfolio approximately 360,000 net acres in the oil-rich window of the Anadarko Basin in Oklahoma. Further information on the Newfield acquisition can be found in the Subsequent Events section of this MD&A.
- Completed the sale of the Company's San Juan assets in New Mexico to DJR Energy, LLC on December 27, 2018.
- Completed the sale of the Company's Pipestone liquids hub in Alberta to Keyera Partnership ("Keyera"), a subsidiary of Keyera Corp., in April 2018. In conjunction with the sale, Keyera will own and construct a natural gas processing facility and will provide Encana with processing services under a competitive fee-for-service arrangement in support of the Company's liquids growth plans in Montney.

Financial Results

- Reported net earnings of $1,069 million, including a net gain on risk management in revenues of $415 million, before tax, and a net foreign exchange loss of $168 million, before tax, as well as deferred tax expense of $149 million.
- Recovered current taxes of approximately $55 million and interest of $17 million primarily due to the successful resolution of certain tax items relating to prior taxation years.
- Generated cash from operating activities of $2,300 million, Non-GAAP Cash Flow of $2,115 million and Non-GAAP Cash Flow Margin of $16.05 per BOE, including the tax items noted above. Cash from operating activities exceeded capital expenditures by $325 million.
- Held cash and cash equivalents of $1,058 million and had available credit facilities of $4.0 billion for total liquidity of $5.1 billion at year end.
- Achieved Net Debt to Adjusted EBITDA of 1.3 times.
- Returned capital to shareholders through the purchase of approximately 20.7 million common shares for total consideration of approximately $250 million and paid dividends of $0.06 per common share totaling $57 million.

Capital Investment

- Reported total capital spending of $1,975 million which was in line with the full year 2018 guidance of approximately $2.0 billion.
- Directed $1,415 million, or 72 percent, of total capital spending to Permian and Montney.
- Focused on highly efficient capital activity and short-cycle high margin projects providing flexibility to respond to fluctuations in commodity prices.

Production

- Average liquids and natural gas production volumes were in line with the full year 2018 guidance ranges.
- Produced average oil and NGL volumes of 168.1 Mbbls/d which accounted for 47 percent of total production volumes. Average oil and plant condensate production volumes of 128.9 Mbbls/d were 77 percent of total liquids production volumes.
- Produced average natural gas volumes of 1,158 MMcf/d which accounted for 53 percent of total production volumes.

Revenues and Operating Expenses

- Achieved all targets set in the full year 2018 guidance ranges; transportation and processing expense of $7.22 per BOE, as well as upstream operating expense of $3.24 per BOE and administrative expense of $1.43 per BOE, excluding long-term incentive costs.
- Focused on market diversification to other downstream markets to maximize realized commodity prices and revenues through a combination of derivative financial instruments and transportation contracts.
- Continued to benefit from secured pipeline transportation capacity to the Dawn and Houston markets to protect against weakening AECO and Midland differentials to NYMEX and WTI, respectively; maintained access to local markets through existing transportation contracts.
- Incurred higher transportation and processing expense of $238 million in 2018, an increase of 28 percent compared to 2017, primarily due to higher production volumes in Montney and Permian, and additional costs incurred in conjunction with the diversification of other downstream markets to capture higher realized prices as discussed above.
- Preserved operational efficiencies achieved in previous years and minimized the effect of inflationary costs.

Subsequent Events

On February 13, 2019, Encana completed the acquisition of all the issued and outstanding shares of common stock of Newfield whereby Encana issued approximately 543.4 million common shares to Newfield shareholders, representing an exchange ratio of 2.6719 Encana common shares for each share of Newfield common stock held. Following the acquisition, Newfield's senior notes totaling $2.45 billion remain outstanding. Newfield's operations are focused on the development of oil-rich properties primarily located in the Anadarko Basin in Oklahoma. The post-acquisition results of operations of Newfield will be included in the Company's interim consolidated results for the period ended March 31, 2019.

On February 13, 2019, the Company confirmed it will proceed with its previously announced plans to spend up to $1.25 billion to purchase common shares, for cancellation, subject to the receipt of regulatory approvals. On February 27, 2019, the Company announced that the TSX accepted its notice of intention to commence a NCIB beginning March 4, 2019 and ending March 3, 2020.

2019 Outlook

Industry Outlook

The oil and gas industry is cyclical and commodity prices are inherently volatile. Oil prices during 2019 are expected to reflect global supply and demand dynamics as well as the geopolitical environment. At a meeting in December 2018, OPEC and certain non-OPEC countries agreed to reduce crude oil production, beginning in January 2019 for an initial period of six months, seeking to balance the global oil market in response to quickly changing fundamentals. Risks to the global economy including trade disputes, U.S. production growth and potential oil supply outages resulting from geopolitical instability in major producing countries, could further contribute to price fluctuations in 2019. OPEC and certain non-OPEC countries are scheduled to meet again in April 2019 to review production levels which could potentially result in other supply adjustments and contribute to price fluctuations.

Natural gas prices in 2019 will be affected by the timing of supply and demand growth and the effects of seasonal weather. Natural gas prices in western Canada have seen significant negative price pressure as strong supply continues to surpass regional demand and stress effective pipeline capacity. Despite near-term price strength related to lower-than-normal storage and a colder than normal start to winter, potential for improvement in longer-term U.S. natural gas prices remains limited, primarily due to continued production increases in both the Northeast U.S. and associated gas production in the Permian Basin.

Company Outlook

Encana is positioned to be flexible in the current price environment in order to continue to achieve strong returns and to balance growth with return of capital to shareholders. The Company enters into derivative financial instruments which mitigate price volatility and help sustain revenues during periods of lower prices. A portion of the Company’s production is sold at prevailing market prices which also allows Encana to participate in potential price increases. As at February 15, 2019, the Company has hedged approximately 88 Mbbls/d of expected oil and condensate production and 989 MMcf/d of expected natural gas production for the remainder of 2019. Additional information on Encana’s hedging program can be found in Note 23 to the Consolidated Financial Statements included in Item 8 of this Annual Report on Form 10-K.

Markets for crude oil and natural gas are exposed to different price risks. While the market price for crude oil tends to move in the same direction as the global market, the Permian Basin experienced wide differentials throughout 2018 due to basin export capacity constraints. Recently, these differentials have narrowed and Encana expects this trend to continue in 2019. Natural gas prices may vary between geographic regions depending on local supply and demand conditions. Encana proactively utilizes transportation contracts to diversify the Company’s downstream markets and reduce significant exposure to any given market. Through a combination of derivative financial instruments and transportation capacity, Encana has mitigated the majority of its exposure to Midland and AECO pricing in 2019. In addition, Encana continues to seek new markets to yield higher returns.

Encana’s 2019 guidance, including capital investment, production and operating expenses, reflects the strategic business combination with Newfield. In 2019, as part of the Company’s commitment to returning capital to shareholders, Encana will also increase its dividend by 25 percent and intends to spend up to $1.25 billion to purchase, for cancellation, Encana common shares. Further information can be found in the Subsequent Events, and Liquidity and Capital Resources sections of this MD&A.

Capital Investment

Total anticipated 2019 capital investment of approximately $2.5 billion to $2.7 billion is expected to be primarily funded from 2019 cash generated from operating activities. Capital investment in Permian and Anadarko is expected to be optimized by Encana’s cube development approach to maximize returns and recovery. Capital investment in Montney is expected to be allocated to both Cutbank Ridge and Pipestone with a focus on maximizing returns from high margin liquids. Encana expects to allocate approximately 75 percent of its total capital spending to these three core growth assets in 2019.

Encana continually strives to improve well performance and lower costs through innovative techniques. Encana's large-scale cube development model utilizes multi-well pads and advanced completion designs to access stacked pay resources to maximize returns and resource recovery from its reservoirs. Encana expects to deploy the cube development model to the Anadarko Basin assets starting in the second quarter of 2019. The application of the cube development is expected to reduce well costs by approximately $1 million per well in 2019 compared to Newfield's 2018 well costs. The impact of Encana's disciplined capital program and continuous innovation create flexibility and opportunity to grow cash flows and production volumes going forward.

Production

As part of the Company's long-term growth strategy, Encana has significantly shifted its production mix to a more balanced portfolio in the recent years, thereby reducing the extent of exposure to market volatility of a particular commodity. In 2019, Encana expects to continue to focus on growing liquids production volumes of 290.0 Mbbls/d to 310.0 Mbbls/d and natural gas production volumes of 1,500 MMcf/d to 1,600 MMcf/d. Liquids production is expected to exceed 50 percent of total production volumes in 2019.

Operating Expenses

Workforce reductions and operating efficiencies attributable to the strategic business combination are expected to reduce indirect operating and administrative costs by approximately $125 million on an annualized basis compared to the aggregate costs of Newfield and Encana prior to the acquisition. These synergies exclude expected restructuring costs to be incurred in 2019. Efficiency improvements and lower service costs are expected to be maintained through the support of the Company's culture of innovation and its focus on continuous improvement in operational execution. Encana expects to continue pursuing innovative ways to reduce upstream operating and administrative expenses. In 2019, Encana expects total costs of $12.75 per BOE to $13.25 per BOE, which includes upstream transportation and processing expense, operating expense, production, mineral and other taxes, as well as administrative expense. Operating expense and administrative expense excludes long-term incentive costs and restructuring costs. Encana strives to offset any inflationary pressures with efficiency improvements and effective supply chain management, including favorable price negotiations.

Further information on Encana's 2019 Corporate Guidance can be accessed on the Company's website at www.encana.com.

Results of Operations

Selected Financial Information

($ millions)	2018	2017 (1)	2016 (1)
Product and Service Revenues			
Upstream product revenues	**$ 4,223**	$ 3,009	$ 2,444
Market optimization	**1,224**	863	647
Service revenues	**10**	20	31
Total Product and Service Revenues	**5,457**	3,892	3,122
Gains (Losses) on Risk Management, Net	**415**	482	(275)
Sublease Revenues	**67**	69	71
Total Revenues	**5,939**	4,443	2,918
Total Operating Expenses (2)	**4,245**	3,375	4,799
Operating Income (Loss)	**1,694**	1,068	(1,881)
Total Other (Income) Expenses	**531**	(362)	(261)
Net Earnings (Loss) Before Income Tax	**1,163**	1,430	(1,620)
Income Tax Expense (Recovery)	**94**	603	(676)
Net Earnings (Loss)	**$ 1,069**	$ 827	$ (944)

(1) 2017 and 2016 revenues have been realigned to conform with the January 1, 2018 adoption of ASU 2014-09 "Revenue from Contracts with Customers", as described in Note 1 to the Consolidated Financial Statements included in Item 8 of this Annual Report on Form 10-K.
(2) Total Operating Expenses include non-cash items such as DD&A, impairments, accretion of asset retirement obligations and long-term incentive costs.

Revenues

Encana's revenues are substantially derived from sales of oil, NGLs and natural gas production. Increases or decreases in Encana's revenues, profitability and future production are highly dependent on the commodity prices the Company receives. Prices are market driven and fluctuate due to factors beyond the Company's control, such as supply and demand, seasonality and geopolitical and economic factors. Canadian Operations realized prices are linked to Edmonton Condensate and AECO, as well as other downstream natural gas benchmarks, including Dawn. The USA Operations realized prices generally reflect WTI and NYMEX benchmark prices, as well as other downstream oil benchmarks. The other downstream benchmarks reflect the diversification of the Company's markets. Realized NGL prices are significantly influenced by oil benchmark prices and the NGL production mix. Recent trends in benchmark prices relevant to Encana are shown in the table below.

Benchmark Prices

(average for the period)	2018	2017	2016
Oil & NGLs			
WTI ($/bbl)	**$ 64.77**	$ 50.95	$ 43.32
Edmonton Condensate (C$/bbl)	**78.88**	66.90	56.18
Natural Gas			
NYMEX ($/MMBtu)	**$ 3.09**	$ 3.11	$ 2.46
AECO (C$/Mcf)	**1.53**	2.43	2.09
Dawn (C$/MMBtu)	**4.07**	3.94	3.39

Production Volumes and Realized Prices

	Production Volumes [1]			Realized Prices [2]		
	2018	2017	2016	**2018**	2017	2016
Oil (Mbbls/d, $/bbl)						
Canadian Operations	**0.4**	0.4	2.0	**$ 52.54**	$ 42.33	$ 36.32
USA Operations	**89.5**	75.9	71.7	**64.05**	49.14	38.67
Total	**89.9**	76.3	73.7	**64.00**	49.10	38.61
NGLs – Plant Condensate (Mbbls/d, $/bbl)						
Canadian Operations	**35.2**	23.1	17.6	**56.31**	50.57	40.97
USA Operations	**3.8**	3.2	2.7	**52.33**	40.64	32.48
Total	**39.0**	26.3	20.3	**55.92**	49.35	39.84
NGLs – Other (Mbbls/d, $/bbl)						
Canadian Operations	**14.0**	6.0	7.6	**27.32**	25.19	12.13
USA Operations	**25.2**	20.5	20.5	**23.39**	19.42	12.53
Total	**39.2**	26.5	28.1	**24.79**	20.72	12.42
Total NGLs (Mbbls/d, $/bbl)						
Canadian Operations	**49.2**	29.1	25.2	**48.05**	45.35	32.32
USA Operations	**29.0**	23.7	23.2	**27.21**	22.30	14.86
Total	**78.2**	52.8	48.4	**40.31**	34.98	23.94
Total Oil & NGLs (Mbbls/d, $/bbl)						
Canadian Operations	**49.6**	29.5	27.2	**48.08**	45.30	32.61
USA Operations	**118.5**	99.6	94.9	**55.03**	42.74	32.84
Total	**168.1**	129.1	122.1	**52.98**	43.33	32.79
Natural Gas (MMcf/d, $/Mcf)						
Canadian Operations	**1,007**	838	966	**2.24**	2.16	1.77
USA Operations	**151**	266	417	**2.28**	3.03	2.29
Total	**1,158**	1,104	1,383	**2.25**	2.37	1.93
Total Production (MBOE/d, $/BOE)						
Canadian Operations	**217.5**	169.1	188.2	**21.34**	18.61	13.82
USA Operations	**143.7**	144.1	164.5	**47.80**	35.16	24.78
Total	**361.2**	313.2	352.7	**31.86**	26.22	18.93
Production Mix (%)						
Oil & Plant Condensate	**36**	33	27			
NGLs – Other	**11**	8	8			
Total Oil & NGLs	**47**	41	35			
Natural Gas	**53**	59	65			
Production Growth - Year Over Year (%) [3]						
Total Oil & NGLs	**30**					
Natural Gas	**5**					
Total Production	**15**					
Core Asset Production						
Oil (Mbbls/d)	**87.6**	72.6	64.1			
NGLs – Plant Condensate (Mbbls/d)	**38.9**	25.8	19.2			
NGLs – Other (Mbbls/d)	**38.0**	24.7	22.9			
Total NGLs (Mbbls/d)	**76.9**	50.5	42.1			
Total Oil & NGLs (Mbbls/d)	**164.5**	123.1	106.2			
Natural Gas (MMcf/d)	**1,091**	826	887			
Total Production (MBOE/d)	**346.3**	260.7	254.2			
% of Total Encana Production	**96**	83	72			

(1) Average daily.
(2) Average per-unit prices, excluding the impact of risk management activities.
(3) Not adjusted for divestitures.

Upstream Product Revenues

($ millions)		Oil		NGLs [1]		Natural Gas [2]		Total
2016 Upstream Product Revenues	**$**	**1,041**	**$**	**424**	**$**	**978**	**$**	**2,443**
Increase (decrease) due to:								
Sales prices		290		171		201		662
Production volumes		36		79		(221)		(106)
2017 Upstream Product Revenues	**$**	**1,367**	**$**	**674**	**$**	**958**	**$**	**2,999**
Increase (decrease) due to:								
Sales prices		**488**		**139**		**(1)**		**626**
Production volumes		**245**		**339**		**(5)**		**579**
2018 Upstream Product Revenues	**$**	**2,100**	**$**	**1,152**	**$**	**952**	**$**	**4,204**

(1) Includes plant condensate.
(2) Natural gas revenues for 2018 exclude a royalty adjustment with no associated production volumes of $19 million (2017 - $10 million; 2016 - $1 million).

Oil Revenues

2018 versus 2017

Oil revenues increased $733 million compared to 2017 primarily due to:

- Higher average realized oil prices of $14.90 per bbl, or 30 percent, increased revenues by $488 million. The increase reflected a higher WTI benchmark price which was up 27 percent and exposure to other downstream benchmark prices in 2018 resulting from the diversification of the Company’s markets, partially offset by weakening regional pricing relative to the WTI benchmark price in the USA Operations; and
- Higher average oil production volumes of 13.6 Mbbls/d increased revenues by $245 million. Higher volumes were primarily due to a successful drilling program in Permian (18.4 Mbbls/d), partially offset by natural declines in Eagle Ford (2.8 Mbbls/d).

2017 versus 2016

Oil revenues increased $326 million compared to 2016 primarily due to:

- Higher average realized oil prices of $10.49 per bbl, or 27 percent, increased revenues by $290 million. The increase reflected a higher WTI benchmark price which was up 18 percent. The increase was also due to higher utilization of pipelines to transport oil to more favourable markets to receive a higher realized price, as well as higher regional pricing in the USA Operations; and
- Higher average oil production volumes of 2.6 Mbbls/d increased revenues by $36 million. Higher volumes were primarily due to a successful drilling program in Permian (11.6 Mbbls/d), partially offset by the sales of the DJ Basin and Gordondale assets in the third quarter of 2016 and the Tuscaloosa Marine Shale assets in the second quarter of 2017 (5.3 Mbbls/d), natural declines in the USA Other Upstream Operations (1.5 Mbbls/d) and Eagle Ford (1.3 Mbbls/d) and production constraints resulting from Hurricane Harvey in Eagle Ford and Permian during the third quarter of 2017 (0.5 Mbbls/d).

NGL Revenues

2018 versus 2017

NGL revenues increased $478 million compared to 2017 primarily due to:

- Higher average realized plant condensate prices of $6.57 per bbl, or 13 percent, increased revenues by $91 million. The increase reflected higher WTI and Edmonton Condensate benchmark prices which were up 27 percent and 18 percent, respectively, partially offset by changes in regional pricing; and
- Higher average realized other NGL prices of $4.07 per bbl, or 20 percent, increased revenues by $48 million. The increase reflected higher other NGL benchmark prices in the USA Operations, partially offset by lower other NGL benchmark prices in Canadian Operations; and
- Higher average plant condensate production volumes of 12.7 Mbbls/d increased revenues by $232 million. Higher volumes were primarily due to successful drilling programs in Montney and Permian (15.3 Mbbls/d), partially offset by natural declines in Duvernay (1.7 Mbbls/d); and
- Higher average other NGL production volumes of 12.7 Mbbls/d increased revenues by $107 million. Higher volumes were primarily due to successful drilling programs in Montney and Permian (14.8 Mbbls/d).

2017 versus 2016

NGL revenues increased $250 million compared to 2016 primarily due to:

- Higher average realized plant condensate prices of $9.51 per bbl, or 24 percent, increased revenues by $93 million. The increase reflected higher WTI and Edmonton Condensate benchmark prices which were up 18 percent and 19 percent, respectively; and
- Higher average realized other NGL prices of $8.30 per bbl, or 67 percent, increased revenues by $78 million resulting from the increase in other NGL benchmark prices; and
- Higher average plant condensate production volumes of 6.0 Mbbls/d increased revenues by $86 million. Higher volumes were primarily due to successful drilling programs in the Core Assets (7.2 Mbbls/d), partially offset by asset sales (1.1 Mbbls/d), which mainly included the Gordondale and DJ Basin assets in the third quarter of 2016; and
- Lower average other NGL production volumes of 1.6 Mbbls/d decreased revenues by $7 million. Lower volumes were primarily due to asset sales (5.9 Mbbls/d), which mainly included the Gordondale and DJ Basin assets in the third quarter of 2016, partially offset by successful drilling programs in the Core Assets (5.1 Mbbls/d).

Natural Gas Revenues

2018 versus 2017

Natural gas revenues decreased $6 million compared to 2017 primarily due to:

- Realized natural gas prices decreased revenues by $1 million resulting from:
  - Lower average realized natural gas prices in the USA Operations of $0.75 per Mcf decreased revenues by $42 million primarily due to weakening regional pricing; and
  - Higher average realized natural gas prices in Canadian Operations of $0.08 per Mcf increased revenues by $41 million primarily due to exposure to other downstream benchmark prices in 2018 resulting from the diversification of the Company's markets, partially offset by a lower AECO benchmark price which was down 37 percent.
- Production volume changes decreased revenues by $5 million resulting from:
  - Lower average production volumes in the USA Operations of 115 MMcf/d decreased revenues by $128 million primarily due to the sale of the Piceance natural gas assets in the third quarter of 2017 (129 MMcf/d), partially offset by a successful drilling program in Permian in 2018 (23 MMcf/d); and
  - Higher average production volumes in Canadian Operations of 169 MMcf/d increased revenues by $123 million resulting from a successful drilling program in Montney (243 MMcf/d), partially offset by asset sales (61 MMcf/d), which mainly include certain assets in Wheatland in the fourth quarter of 2017, and lower volumes from Deep Panuke where the Company has ceased operations and has begun planning decommissioning activities (17 MMcf/d).

2017 versus 2016

Natural gas revenues decreased $20 million compared to 2016 primarily due to:

- Lower average natural gas production volumes of 279 MMcf/d decreased revenues by $221 million. Lower volumes were primarily due to asset sales (198 MMcf/d) which mainly included the Piceance natural gas assets in the third quarter of 2017 and the Gordondale and DJ Basin assets in the third quarter of 2016, natural declines in Other Upstream Operations (77 MMcf/d) and increased downtime resulting from scheduled third-party plant maintenance in Montney (19 MMcf/d), partially offset by a successful drilling program in Permian (17 MMcf/d);

partially offset by:

- Higher average realized natural gas prices of $0.44 per Mcf, or 23 percent, increased revenues by $201 million. The increase reflected higher NYMEX, AECO and Algonquin City Gate benchmark prices which were up 26 percent, 16 percent and 19 percent, respectively. The increase was also due to the diversification of the Company's downstream markets to capture a higher realized price.

Gains (Losses) on Risk Management, Net

As a means of managing commodity price volatility, Encana enters into commodity derivative financial instruments on a portion of its expected oil, NGL and natural gas production volumes. The Company's commodity price mitigation program reduces volatility and helps sustain revenues during periods of lower prices. Further information on the Company's commodity price positions as at December 31, 2018 can be found in Note 23 to the Consolidated Financial Statements included in Item 8 of this Annual Report on Form 10-K.

The following table provides the effects of Encana's risk management activities on revenues.

	$ millions			Per-Unit		
	2018	2017	2016	**2018**	2017	2016
Realized Gains (Losses) on Risk Management						
Commodity Price [1]						
Oil ($/bbl)	**$ (235)**	$ 18	$ 271	**$ (7.16)**	$ 0.66	$ 10.07
NGLs ($/bbl) [2]	**(89)**	(5)	-	**(3.10)**	(0.26)	(0.04)
Natural Gas ($/Mcf)	**218**	20	85	**0.51**	0.05	0.17
Other [3]	**2**	7	5	**-**	-	-
Total ($/BOE)	**(104)**	40	361	**$ (0.80)**	$ 0.29	$ 2.76
Unrealized Gains (Losses) on Risk Management	**519**	442	(636)			
Total Gains (Losses) on Risk Management, Net	**$ 415**	$ 482	$ (275)			

(1) Includes realized gains and losses related to the Canadian and USA Operations.
(2) Includes plant condensate.
(3) Other primarily includes realized gains or losses from Market Optimization and other derivative contracts with no associated production volumes.

Encana recognizes fair value changes from its risk management activities each reporting period. The changes in fair value result from new positions and settlements that occur during each period, as well as the relationship between contract prices and the associated forward curves. Realized gains or losses on risk management activities related to commodity price mitigation are included in the Canadian and USA Operations and Market Optimization revenues as the contracts are cash settled. Unrealized gains or losses on fair value changes of unsettled contracts are included in the Corporate and Other segment.

Market Optimization Revenues

Market Optimization product revenues relate to activities that provide operational flexibility and cost mitigation for transportation commitments, product type, delivery points and customer diversification.

($ millions)	**2018**	2017	2016
Market Optimization	**$ 1,224**	$ 863	$ 647

2018 versus 2017

Market Optimization revenues increased $361 million compared to 2017 primarily due to:

- Higher sales of third-party purchased volumes, primarily related to natural gas, used for optimization activities and long-term marketing arrangements associated with certain divestitures from prior years ($436 million), partially offset by lower natural gas benchmark prices ($75 million).

2017 versus 2016

Market Optimization revenues increased $216 million compared to 2016 primarily due to:

- Higher natural gas benchmark prices ($166 million) and higher sales of third-party purchased volumes, primarily related to natural gas, used for optimization activities and long-term marketing arrangements associated with certain divestitures from prior years ($50 million).

Sublease Revenues

Sublease revenues primarily includes amounts related to the sublease of office space in The Bow office building recorded in the Corporate and Other segment. Further information on The Bow office sublease can be found in Note 14 to the Consolidated Financial Statements included in Item 8 of this Annual Report on Form 10-K.

Operating Expenses

Production, Mineral and Other Taxes

Production, mineral and other taxes include production and property taxes. Production taxes are generally assessed as a percentage of oil and natural gas production revenues. Property taxes are generally assessed based on the value of the underlying assets.

	$ millions			$/BOE		
	2018	2017	2016	**2018**	2017	2016
Canadian Operations	**$ 16**	$ 20	$ 23	**$ 0.20**	$ 0.33	$ 0.33
USA Operations	**131**	92	76	**$ 2.50**	$ 1.74	$ 1.27
Total	**$ 147**	$ 112	$ 99	**$ 1.11**	$ 0.98	$ 0.77

2018 versus 2017

Production, mineral and other taxes increased $35 million compared to 2017 primarily due to:

- Higher liquids prices in Permian and Eagle Ford and higher production volumes in Permian ($40 million) and lower production taxes in 2017 from tax recoveries in the USA Operations ($8 million);

partially offset by:

- Asset sales ($15 million), which mainly include certain assets in Wheatland in the fourth quarter of 2017 and the Piceance natural gas assets in the third quarter of 2017.

2017 versus 2016

Production, mineral and other taxes increased $13 million compared to 2016 primarily due to:

- Higher prices in the USA Operations and higher liquids production volumes in Permian ($31 million);

partially offset by:

- The sales of the DJ Basin and Gordondale assets in the third quarter of 2016 and the Piceance natural gas assets in the third quarter of 2017 ($10 million) and the recovery of certain production taxes in the USA Operations ($8 million).

Transportation and Processing

Transportation and processing expense includes transportation costs incurred to move product from production points to sales points including gathering, compression, pipeline tariffs, trucking and storage costs. Encana also incurs costs related to processing provided by third parties or through ownership interests in processing facilities to bring raw production to sales-quality product.

	$ millions			$/BOE		
	2018	2017	2016	**2018**	2017	2016
Canadian Operations	**$ 828**	$ 578	$ 576	**$ 10.42**	$ 9.35	$ 8.35
USA Operations	**124**	164	260	**$ 2.37**	$ 3.12	$ 4.33
Upstream Transportation and Processing	**952**	742	836	**$ 7.22**	$ 6.49	$ 6.48
Market Optimization	**131**	103	87			
Corporate & Other	**-**	-	(22)			
Total	**$ 1,083**	$ 845	$ 901			

2018 versus 2017

Transportation and processing expense increased $238 million compared to 2017 primarily due to:

- Higher production volumes and gathering and processing fees in Montney ($147 million) and Permian ($15 million), higher downstream processing and transportation costs due to higher volumes and costs relating to the diversification of the Company's downstream markets in Montney ($137 million) and Permian ($24 million);

partially offset by:

- Asset sales ($67 million), which mainly include the Piceance natural gas assets in the third quarter of 2017 and certain assets in Wheatland in the fourth quarter of 2017, and lower volumes from Deep Panuke where the Company has ceased operations and has begun planning decommissioning activities ($23 million).

2017 versus 2016

Transportation and processing expense decreased $56 million compared to 2016 primarily due to:

- Asset sales ($107 million), which mainly include the DJ Basin and Gordondale assets in the third quarter of 2016 and the Piceance natural gas assets in the third quarter of 2017, the renegotiation and expiration of certain transportation contracts ($32 million), lower natural gas production volumes and lower gas gathering and processing fees in Montney and Other Upstream Operations ($9 million) and lower activity in Duvernay ($4 million);

partially offset by:

- Increased downstream processing and transportation costs primarily in Montney and Duvernay due to Encana's focus on liquids rich wells in the plays and costs relating to the diversification of the Company's downstream markets ($40 million), higher volumes and prices in Permian ($25 million), unrealized risk management gains on power financial derivative contracts in 2016 ($22 million) and the higher U.S./Canadian dollar exchange rate ($11 million).

Operating

Operating expense includes costs paid by Encana, net of amounts capitalized, to operate oil and gas properties in which the Company has a working interest. These costs primarily include labour, service contract fees, chemicals and fuel.

	$ millions			$/BOE		
	2018	2017	2016	**2018**	2017	2016
Canadian Operations	**$ 118**	$ 122	$ 152	**$ 1.45**	$ 1.92	$ 2.16
USA Operations	**305**	331	394	**$ 5.80**	$ 6.18	$ 6.44
Upstream Operating Expense (1)	**423**	453	546	**$ 3.18**	$ 3.88	$ 4.16
Market Optimization	**16**	35	35			
Corporate & Other	**15**	18	17			
Total	**$ 454**	$ 506	$ 598			

(1) 2018 Upstream Operating Expense per BOE includes a recovery of long-term incentive costs of $0.06/BOE (2017 - long-term incentive costs of $0.19/BOE; 2016 - long-term incentive costs of $0.29/BOE).

2018 versus 2017

Operating expense decreased $52 million compared to 2017 primarily due to:

- Lower long-term incentive costs resulting from the decrease in Encana's share price in 2018 compared to 2017 ($47 million) and asset sales ($39 million), which mainly include the Piceance natural gas assets in the third quarter of 2017 and certain assets in Wheatland in the fourth quarter of 2017;

partially offset by:

- Higher activity in Montney and Permian ($40 million).

2017 versus 2016

Operating expense decreased $92 million compared to 2016 primarily due to:

- Asset sales ($66 million), which mainly included the DJ Basin and Gordondale assets in the third quarter of 2016, the Piceance natural gas assets in the third quarter of 2017 and the Tuscaloosa Marine Shale assets in the second quarter of 2017, lower salaries and benefits and long-term incentive costs due to higher headcount dedicated to the capital program and a smaller increase in Encana's share price in 2017 compared to 2016 ($47 million) and cost-saving initiatives ($24 million);

partially offset by:

- Higher activity in Permian and Montney ($39 million) and the higher U.S./Canadian dollar exchange rate ($4 million).

Further information on Encana's long-term incentives can be found in Note 20 to the Consolidated Financial Statements included in Item 8 of this Annual Report on Form 10-K.

Purchased Product

Purchased product expense includes purchases of oil, NGLs and natural gas from third parties that are used to provide operational flexibility and cost mitigation for transportation commitments, product type, delivery points and customer diversification.

($ millions)		**2018**		2017		2016
Market Optimization	**$**	**1,100**	$	788	$	586

2018 versus 2017

Purchased product expense increased $312 million compared to 2017 primarily due to:

- Higher third-party volumes purchased, primarily related to natural gas, for optimization activities and long-term marketing arrangements associated with certain divestitures from prior years ($423 million), partially offset by lower natural gas benchmark prices ($111 million).

2017 versus 2016

Purchased product expense increased $202 million compared to 2016 primarily due to:

- Higher natural gas benchmark prices ($152 million) and higher third-party volumes purchased, primarily related to natural gas, for optimization activities and long-term marketing arrangements associated with certain divestitures from prior years ($50 million).

Depreciation, Depletion & Amortization

Proved properties within each country cost centre are depleted using the unit-of-production method based on proved reserves as discussed in Note 1 to the Consolidated Financial Statements included in Item 8 of this Annual Report on Form 10-K. Depletion rates are impacted by impairments, acquisitions, divestitures and foreign exchange rates, as well as fluctuations in 12-month average trailing prices which affect proved reserves volumes. Additional information can be found in the Critical Accounting Estimates section of this MD&A under Upstream Assets and Reserve Estimates. Corporate assets are carried at cost and depreciated on a straight-line basis over the estimated service lives of the assets.

	$ millions			$/BOE		
	2018	2017	2016	**2018**	2017	2016
Canadian Operations	**$ 361**	$ 236	$ 260	**$ 4.55**	$ 3.82	$ 3.77
USA Operations	**860**	530	523	**$ 16.39**	$ 10.09	$ 8.68
Upstream DD&A	**1,221**	766	783	**$ 9.26**	$ 6.70	$ 6.06
Market Optimization	**1**	1	-			
Corporate & Other	**50**	66	76			
Total	**$ 1,272**	$ 833	$ 859			

2018 versus 2017

DD&A increased $439 million compared to 2017 primarily due to:

- Higher depletion rates in the USA and Canadian Operations ($318 million and $67 million, respectively) and higher production volumes in Canadian Operations ($59 million).

The depletion rates in the Canadian and USA Operations increased $0.73 per BOE and $6.30 per BOE, respectively, compared to 2017 primarily due to:

- Higher capital spending resulting from an increased capital program in 2018, transfers of unproved property costs of previously acquired assets which have been evaluated for proved reserves and lower reserve volumes from the sale of the Piceance natural gas assets in the USA Operations in the third quarter of 2017.

2017 versus 2016

DD&A decreased $26 million compared to 2016 primarily due to:

- Lower production volumes ($85 million) and lower straight-line depreciation on corporate assets ($12 million), partially offset by higher depletion rates primarily in the USA Operations ($63 million) and the higher U.S./Canadian dollar exchange rate ($5 million).

The depletion rates in the Canadian and USA Operations increased $0.05 per BOE and $1.41 per BOE, respectively, compared to 2016 primarily due to:

- Lower reserve volumes from the sale of the Piceance natural gas assets in the third quarter of 2017, partially offset by ceiling test impairments recognized in the first six months of 2016 in the Canadian and USA Operations, and the sale of the DJ Basin assets in the third quarter of 2016. The sale of the Piceance natural gas assets resulted in the recognition of a gain on divestiture, whereas proceeds from the sale of the DJ Basin assets were deducted from the U.S. full cost pool. Additional information on the divestitures can be found in Note 8 to the Consolidated Financial Statements included in Item 8 of this Annual Report on Form 10-K.

Impairments

Under full cost accounting, the carrying amount of Encana's oil and natural gas properties within each country cost centre is subject to a ceiling test at the end of each quarter. Ceiling test impairments are recognized when the capitalized costs, net of accumulated depletion and the related deferred income taxes, exceed the sum of the estimated after-tax future net cash flows from proved reserves as calculated under SEC requirements using the 12-month average trailing prices and discounted at 10 percent.

($ millions)		**2018**		2017		2016
Canadian Operations	**$**	**-**	$	-	$	493
USA Operations		**-**		-		903
Total	**$**	**-**	$	-	$	1,396

The Company did not recognize any ceiling test impairments for 2018 and 2017. The ceiling test impairments in 2016 were primarily due to the decline in the 12-month average trailing prices, which reduced the Canadian and USA Operations proved reserves volumes and values as calculated under SEC requirements. For additional information on the 12-month average trailing prices used in the ceiling test calculations, refer to Note 27 to the Consolidated Financial Statements included in Item 8 of this Annual Report on Form 10-K.

Administrative

Administrative expense represents costs associated with corporate functions provided by Encana staff in the Calgary and Denver offices. Costs primarily include salaries and benefits, general office, information technology and long-term incentive costs.

		2018		2017		2016
Administrative ($ millions)	**$**	**157**	$	254	$	309
Administrative ($/BOE) [(1)]	**$**	**1.18**	$	2.22	$	2.40

(1) 2018 administrative expense per BOE includes a recovery of long-term incentive costs of $0.25/BOE (2017 - long-term incentive costs of $0.67/BOE). 2016 administrative expense per BOE includes long-term incentive costs and restructuring costs of $0.93/BOE.

2018 versus 2017

Administrative expense in 2018 decreased $97 million compared to 2017 primarily due to lower long-term incentive costs resulting from the decrease in Encana's share price in 2018 compared to 2017 ($109 million).

2017 versus 2016

Administrative expense in 2017 decreased $55 million compared to 2016 primarily due to lower restructuring costs ($34 million), lower third-party payments relating to previously divested assets ($11 million) as well as lower long-term incentive costs resulting from a smaller increase in Encana's share price in 2017 compared to 2016 ($10 million).

Other (Income) Expenses

($ millions)		**2018**		2017		2016
Interest	**$**	**351**	$	363	$	397
Foreign Exchange (Gain) Loss, Net		**168**		(279)		(210)
(Gain) Loss on Divestitures, Net		**(5)**		(404)		(390)
Other (Gains) Losses, Net		**17**		(42)		(58)
Total Other (Income) Expenses	**$**	**531**	$	(362)	$	(261)

Interest

Interest expense primarily includes interest on Encana's long-term debt arising from U.S. dollar denominated unsecured notes. Encana also incurs interest on the Company's long-term obligations for The Bow office building and capital leases. Further details on changes in interest can be found in Note 4 to the Consolidated Financial Statements included in Item 8 of this Annual Report on Form 10-K.

2018 versus 2017

Interest expense in 2018 decreased $12 million compared to 2017 primarily due to a $17 million recovery of other interest resulting from the successful resolution of certain tax items related to prior taxation years compared to $11 million in 2017, and lower interest on capital leases ($4 million).

2017 versus 2016

Interest expense in 2017 decreased $34 million compared to 2016 primarily due to lower interest on debt ($29 million) resulting from the early retirement of long-term debt in March 2016. Further information on the March 2016 debt retirement can be found in the Liquidity and Capital Resources section of this MD&A.

Foreign Exchange (Gain) Loss, Net

Foreign exchange gains and losses result from the impact of fluctuations in the Canadian to U.S. dollar exchange rate. Further details on changes in foreign exchange gains or losses can be found in Note 5 to the Consolidated Financial Statements included in Item 8 of this Annual Report on Form 10-K. Additional information on foreign exchange rates and the effects of foreign exchange rate changes can be found in Items 6 and 7A of this Annual Report on Form 10-K.

2018 versus 2017

In 2018, Encana recorded a net foreign exchange loss of $168 million compared to a net gain of $279 million in 2017. The change of $447 million was primarily due to unrealized foreign exchange losses on the translation of U.S. dollar financing debt issued from Canada compared to gains in 2017 ($601 million) and unrealized losses on the translation of U.S. dollar risk management contracts issued from Canada compared to gains in 2017 ($68 million), partially offset by higher unrealized foreign exchange gains on the translation of intercompany notes ($145 million) and realized foreign exchange gains on the settlement of intercompany notes compared to losses in 2017 ($59 million).

2017 versus 2016

In 2017, Encana recorded a higher net foreign exchange gain compared to 2016 ($69 million). The change was primarily due to higher unrealized foreign exchange gains on the translation of U.S. dollar financing debt issued from Canada ($113 million) and unrealized foreign exchange gains on the translation of U.S. dollar risk management contracts issued from Canada compared to losses in 2016 ($48 million), partially offset by realized foreign exchange losses on the settlement of U.S. dollar financing debt issued from Canada compared to gains in 2016 ($87 million). In 2017, unrealized foreign exchange on the translation of U.S. dollar financing debt issued from Canada included an out-of-period adjustment of $68 million, before tax, in respect of unrealized losses on a foreign-denominated capital lease obligation since December 31, 2013. Further information on the out-of-period adjustment can be found in Note 5 to the Consolidated Financial Statements included in Item 8 of this Annual Report on Form 10-K.

(Gain) Loss on Divestitures, Net

Amounts received from the Company's divestiture transactions are deducted from the respective Canadian and U.S. full cost pools, except for divestitures that result in a significant alteration between capitalized costs and proved reserves in a country cost centre, in which case a gain or loss is recognized. Additional information regarding gains on divestitures can be found in Note 8 to the Consolidated Financial Statements included in Item 8 of this Annual Report on Form 10-K.

2017

Gain on divestitures in 2017 primarily included the before tax gain on the sale of the Piceance natural gas assets of approximately $406 million.

2016

Gain on divestitures in 2016 primarily included the gain on the sale of the Gordondale assets of approximately $394 million.

Other (Gains) Losses, Net

Other (gains) losses, net, primarily includes other non-recurring revenues or expenses and may also include items such as interest income on short-term investments, interest received from tax authorities, reclamation charges relating to decommissioned assets and adjustments related to other assets.

2018

Other losses in 2018 primarily includes the write-down of long-term receivables relating to Other Upstream Operations of $20 million, acquisition costs relating to the merger agreement with Newfield of $7 million, and reclamation charges relating to decommissioned assets of $4 million, partially offset by interest income on short-term investments of $8 million and the recovery of sales taxes relating to previously divested investments of $7 million.

2017

Other gains in 2017 primarily included interest received of $33 million resulting from the successful resolution of certain tax items previously assessed by the tax authorities relating to prior taxation years and interest income on short-term investments of $6 million, partially offset by reclamation charges relating to decommissioned assets of $4 million.

2016

Other gains in 2016 primarily included a gain of $89 million on the early retirement of long-term debt as discussed in the Liquidity and Capital Resources section of this MD&A, partially offset by a one-time third-party payment relating to a previously divested asset of $20 million and reclamation charges relating to decommissioned assets of $7 million.

Income Tax

($ millions)	2018	2017	2016
Current Income Tax Expense (Recovery)	**$ (55)**	$ (63)	$ (78)
Deferred Income Tax Expense (Recovery)	**149**	666	(598)
Income Tax Expense (Recovery)	**$ 94**	$ 603	$ (676)
Effective Tax Rate	**8.1%**	42.2%	41.7%

Income Tax Expense (Recovery)

2018 versus 2017

Total income tax expense in 2018 decreased $509 million compared to 2017 mainly as a result of lower deferred income tax expense ($517 million) which was primarily due to:

- Lower net earnings before income tax in 2018 compared to 2017 ($267 million); and
- A reduction in the 2018 U.S. federal corporate tax rate from 35 percent to 21 percent resulting from U.S. Tax Reform.

The current income tax recovery in 2018 of $55 million was primarily due to the successful resolution of certain tax items relating to prior taxation years.

There has been no change in 2018 to the provisional tax adjustment of $327 million recognized in December 2017 resulting from the re-measurement of the Company's tax position due to a reduction of the U.S. federal corporate tax rate under U.S. Tax Reform. As at December 31, 2018, the Company has completed its assessment of the income tax effects in respect of the provisional adjustment related to U.S. Tax Reform. Additional information on U.S. Tax Reform can be found in Note 6 to the Consolidated Financial Statements included in Item 8 of this Annual Report on Form 10-K.

2017 versus 2016

Total income tax in 2017 was an expense of $603 million compared to a recovery of $676 million in 2016 mainly as a result of deferred income tax expense in 2017 of $666 million compared to a recovery of $598 million in 2016. The deferred income tax was primarily due to:

- Net earnings before income tax in 2017 of $1,430 million compared to a net loss before income tax of $1,620 million in 2016; and
- Deferred tax expense in 2017 included a provisional adjustment of $327 million resulting from U.S. Tax Reform as discussed above; and
- Deferred tax recovery in 2016 was primarily due to the recognition of non-cash ceiling test impairments of $1,396 million, before tax.

The current income tax recovery in 2017 of $63 million was primarily due to the successful resolution of certain tax items previously assessed by the taxing authorities relating to prior taxation years, as well as the reclassification of $10 million of U.S. alternative minimum tax to a long-term receivable from a deferred tax asset due to U.S. Tax Reform.

Effective Tax Rate

Encana's annual effective income tax rate is primarily impacted by earnings, income tax related to foreign operations, the effect of legislative changes including U.S. Tax Reform, non-taxable capital gains and losses, tax differences on divestitures and transactions, and partnership tax allocations in excess of funding. Additional information on income taxes can be found in Note 6 to the Consolidated Financial Statements included in Item 8 of this Annual Report on Form 10-K.

The effective tax rate for 2018 was 8.1 percent, which is lower than the Canadian statutory rate of 27 percent primarily due to the impact of the foreign jurisdictional tax rates relative to the Canadian statutory tax rate applied to jurisdictional earnings, partnership tax allocations in excess of funding and the successful resolution of certain tax items relating to prior taxation years.

The effective tax rate for 2017 was 42.2 percent, which was higher than the Canadian statutory tax rate of 27 percent primarily due to U.S. Tax Reform, which increased Encana's effective tax rate by 22.9 percent, as well as the impacts from tax reassessments discussed above. The effective tax rate for 2016 exceeded the Canadian statutory tax rate of 27 percent primarily due to the impact of the foreign jurisdictional tax rates relative to the Canadian statutory tax rate applied to jurisdictional earnings.

Tax interpretations, regulations and legislation, including U.S. Tax Reform and potential Treasury Department regulations and guidance, in the various jurisdictions in which the Company and its subsidiaries operate are subject to change and interpretation. As a result, there are tax matters under review for which the timing of resolution is uncertain. The Company believes that the provision for income taxes is adequate.

Liquidity and Capital Resources

Sources of Liquidity

The Company has the flexibility to access cash equivalents and a range of funding alternatives at competitive rates through committed revolving bank credit facilities as well as debt and equity capital markets. Encana closely monitors the accessibility of cost-effective credit and ensures that sufficient liquidity is in place to fund capital expenditures and dividend payments. In addition, the Company may use cash and cash equivalents, cash from operating activities, or proceeds from asset divestitures and share issuances to fund its operations or to manage its capital structure as discussed below. At December 31, 2018, $711 million in cash and cash equivalents was held by U.S. subsidiaries. The cash held by U.S. subsidiaries is accessible and may be subject to additional Canadian income taxes and U.S. withholding taxes if repatriated.

The Company's capital structure consists of total shareholders' equity plus long-term debt, including the current portion. The Company's objectives when managing its capital structure are to maintain financial flexibility to preserve Encana's access to capital markets and its ability to meet financial obligations and finance internally generated growth, as well as potential acquisitions. Encana has a practice of maintaining capital discipline and strategically managing its capital structure by adjusting capital spending, adjusting dividends paid to shareholders, issuing new shares, purchasing shares for cancellation through a NCIB, issuing new debt or repaying existing debt.

($ millions, except as indicated)	**2018**	2017	2016
Cash and Cash Equivalents	**$ 1,058**	$ 719	$ 834
Available Credit Facility – Encana [(1)]	**2,500**	3,000	3,000
Available Credit Facility – U.S. Subsidiary [(1)]	**1,500**	1,500	1,500
Total Liquidity	**5,058**	5,219	5,334
Long-Term Debt, including current portion	**4,198**	4,197	4,198
Total Shareholders' Equity	**7,447**	6,728	6,126
Debt to Capitalization (%) [(2)]	**36**	38	41
Debt to Adjusted Capitalization (%) [(3)]	**22**	22	23

(1) Collectively, the "Credit Facilities".
(2) Calculated as long-term debt, including the current portion, divided by shareholders' equity plus long-term debt, including the current portion.
(3) A non-GAAP measure which is defined in the Non-GAAP Measures section of this MD&A.

In the first quarter of 2018, the Company amended the capacity of its Encana Credit Facility from $3.0 billion to $2.5 billion and extended the maturity for both Credit Facilities to July 2022.

Encana is currently in compliance with, and expects that it will continue to be in compliance with, all financial covenants under the Credit Facilities. Management monitors Debt to Adjusted Capitalization, which is a non-GAAP measure defined in the Non-GAAP Measures section of this MD&A, as a proxy for Encana's financial covenant under the Credit Facilities, which requires debt to adjusted capitalization to be less than 60 percent. The definitions used in the covenant under the Credit Facilities adjust capitalization for cumulative historical ceiling test impairments that were recorded as at December 31, 2011 in conjunction with the Company's January 1, 2012 adoption of U.S. GAAP. Additional information on financial covenants can be found in Note 13 to the Consolidated Financial Statements included in Item 8 of this Annual Report on Form 10-K.

Sources and Uses of Cash

During 2018, Encana primarily generated cash through operating activities. The following table summarizes the sources and uses of the Company's cash and cash equivalents.

($ millions)	Activity Type	2018	2017	2016
Sources of Cash and Cash Equivalents				
Cash from operating activities	Operating	**$ 2,300**	$ 1,050	$ 625
Proceeds from divestitures	Investing	**493**	736	1,262
Issuance of common shares, net of offering costs	Financing	**-**	-	1,129
Other	Investing	**-**	77	51
		2,793	1,863	3,067
Uses of Cash and Cash Equivalents				
Capital expenditures	Investing	**1,975**	1,796	1,132
Acquisitions	Investing	**17**	54	210
Net repayment of revolving long-term debt	Financing	**-**	-	650
Repayment of long-term debt	Financing	**-**	-	400
Purchase of common shares	Financing	**250**	-	-
Dividends on common shares	Financing	**56**	57	51
Other	Investing/Financing	**146**	82	66
		2,444	1,989	2,509
Foreign Exchange Gain (Loss) on Cash and Cash Equivalents Held in Foreign Currency		**(10)**	11	5
Increase (Decrease) in Cash and Cash Equivalents		**$ 339**	$ (115)	$ 563

Operating Activities

Cash from operating activities in 2018 was $2,300 million and was primarily a reflection of increases in liquids production volumes, recovering realized liquids prices, the Company's efforts in maintaining cost efficiencies achieved in previous years and changes in non-cash working capital. Additional detail on changes in non-cash working capital can be found in Note 24 to the Consolidated Financial Statements included in Item 8 of this Annual Report on Form 10-K. Encana expects it will continue to meet the payment terms of its suppliers.

Non-GAAP Cash Flow in 2018 was $2,134 million and was primarily impacted by the items affecting cash from operating activities which are discussed below and in the Results of Operations section of this MD&A.

2018 versus 2017

Net cash from operating activities increased $1,250 million compared to 2017 primarily due to:

- Higher liquids production volumes ($584 million) and realized liquids prices ($627 million), changes in non-cash working capital ($498 million) and higher natural gas production volumes and realized natural gas prices in Canadian Operations ($123 million and $41 million, respectively);

partially offset by:

- Higher transportation and processing expense ($238 million), realized losses on risk management in revenues in 2018 compared to gains in 2017 ($144 million), lower natural gas production volumes and realized natural gas prices in the USA Operations ($128 million and $42 million, respectively), higher production, mineral and other taxes ($35 million) and lower interest income recorded in other gains (losses), net ($30 million).

2017 versus 2016

Net cash from operating activities increased $425 million compared to 2016 primarily due to:

- Higher realized commodity prices ($662 million), higher liquids production volumes ($115 million), lower operating expense, excluding non-cash long-term incentive costs ($73 million), lower transportation and processing expense ($56 million), higher interest income recorded in other gains ($39 million), lower restructuring costs ($34 million) and lower interest on long-term debt ($29 million);

partially offset by:

- Lower realized gains on risk management included in revenues ($321 million), lower natural gas production volumes ($221 million) and changes in non-cash working capital ($66 million).

Investing Activities

Capital expenditures and divestitures have been Encana's primary investing activities over the past three years. The capital spending program increased in 2018 compared to 2017 as liquids prices continued to recover. Capital expenditures and divestiture activity are summarized in Notes 2 and 8, respectively, to the Consolidated Financial Statements included in Item 8 of this Annual Report on Form 10-K.

2018

Net cash used in investing activities in 2018 was $1,555 million primarily due to capital expenditures, partially offset by proceeds from divestitures. Capital expenditures in 2018 increased $179 million compared to 2017 due to the increase in Encana's capital program for 2018. This increase was primarily in Montney ($170 million), Eagle Ford ($90 million), and Duvernay ($39 million), partially offset by lower capital expenditures in Permian ($102 million). Cash from operating activities exceeded capital expenditures by $325 million.

Acquisitions in 2018 were $17 million, which primarily included purchases with oil and liquids rich potential.

Divestitures in 2018 were $493 million, which primarily included the sale of the San Juan assets in New Mexico, comprising approximately 182,000 net acres, and the sale of the Pipestone midstream assets in Alberta.

2017

Net cash used in investing activities in 2017 was $1,037 million primarily due to capital expenditures, partially offset by proceeds from divestitures. Capital expenditures in 2017 increased $664 million compared to 2016 due to the increase in Encana's capital program for 2017. Capital expenditures in the Core Assets totaled $1,729 million, representing 96 percent of total capital expenditures, and increased $635 million compared to 2016, primarily in Permian ($372 million), Eagle Ford ($93 million) and Montney ($205 million). Capital expenditures exceeded cash from operating activities by $746 million and the difference was funded using cash on hand and proceeds from divestitures.

Acquisitions in 2017 were $54 million, which primarily included purchases with oil and liquids rich potential.

Divestitures in 2017 were $736 million, which primarily included the sale of the Piceance natural gas assets in northwestern Colorado, comprising approximately 550,000 net acres of leasehold and 3,100 operated wells. Divestitures also included the sale of the Tuscaloosa Marine Shale assets in Mississippi and Louisiana and the sale of certain properties that did not complement Encana's existing portfolio of assets.

2016

Net cash used in investing activities in 2016 was $29 million primarily due to capital expenditures and acquisitions, partially offset by proceeds from divestitures. Capital expenditures in 2016 decreased $1,100 million compared to 2015 due to a reduced capital program and cost savings initiatives implemented in 2016. Capital expenditures in the Core Assets totaled $1,094 million, representing 97 percent of total capital expenditures, and decreased $756 million compared to 2015, primarily in Eagle Ford ($359 million), Permian ($287 million) and Duvernay ($92 million).

Capital expenditures exceeded cash from operating activities by $507 million and the difference was funded using proceeds from divestitures.

Acquisitions in 2016 were $210 million, which primarily included $135 million for the purchase of natural gas gathering and water handling assets in Piceance located in Colorado. Acquisitions in 2016 also included the purchase of land and property in Eagle Ford with oil and liquids rich potential.

Divestitures in 2016 were $1,262 million, which primarily included the following:

- Proceeds of approximately $633 million, after closing and other adjustments, for the sale of the DJ Basin assets located in northern Colorado, comprising approximately 51,000 net acres;
- Proceeds of approximately C$600 million ($455 million), after closing adjustments, for the sale of the Gordondale assets which included approximately 54,200 net acres of land and associated infrastructure in Montney located in northwestern Alberta; and
- Proceeds of approximately $135 million from the sale of certain natural gas leasehold interests in Piceance located in Colorado.

Financing Activities

Net cash used in financing activities over the past three years has been impacted by Encana's strategy to enhance liquidity, strengthen its balance sheet and return value to shareholders through the purchase of common shares under a NCIB. The Company has paid dividends each of the past three years.

2018 versus 2017

Net cash used in financing activities in 2018 increased $257 million from 2017. The change was primarily due to the purchase of common shares under a NCIB in 2018 ($250 million) as discussed below.

2017 versus 2016

Net cash used in financing activities in 2017 increased $101 million from 2016. The change was primarily due to the issuance of common shares in 2016 ($1,129 million), partially offset by a net repayment of revolving long-term debt ($650 million) and a repayment of long-term debt ($400 million) in 2016.

The transactions affecting the changes in financing activities are discussed in more detail below.

2018 and 2017

Encana's long-term debt, including the current portion of $500 million which is due May 2019, totaled $4,198 million at December 31, 2018 (2017 - $4,197 million). As at December 31, 2018, over 73 percent of the Company's debt is not due until 2030 and beyond.

The Company continues to have full access to the Credit Facilities, which remain committed through July 2022. The Credit Facilities provide financial flexibility and allow the Company to fund its operations, development activities or capital program. At December 31, 2018, Encana had no outstanding balance under the Credit Facilities and $147 million in undrawn letters of credit issued in the normal course of business primarily as collateral security, to support future abandonment liabilities and for transportation arrangements.

Encana renewed its Canadian shelf prospectus in August 2018 and has access to a U.S. shelf registration statement filed in 2017, whereby the Company may issue from time to time, debt securities, common shares, Class A preferred shares, subscription receipts, warrants, units, share purchase contracts and share purchase units in Canada and/or the U.S. At December 31, 2018, $6.0 billion remained accessible under the Canadian shelf prospectus. The ability to issue securities under the Canadian shelf prospectus or U.S. shelf registration statement is dependent upon market conditions.

2016

In March 2016, the Company completed tender offers (collectively, the "Tender Offers") for certain of the Company's outstanding senior notes (collectively, the "Notes") and accepted for purchase $489 million aggregate principal amount of Notes. The Company paid an aggregate amount of $406 million, including accrued and unpaid interest of $6 million and an early tender premium of $14 million, which resulted in the recognition of a net gain on the early debt retirement of $89 million, before tax. The Company used cash on hand and borrowings under the Credit Facilities to fund the Tender Offers.

On September 23, 2016, Encana completed a public offering (the "2016 Share Offering") of 107,000,000 common shares of Encana at a price of $9.35 per common share for gross proceeds of approximately $1.0 billion ($981 million of net cash proceeds). On October 4, 2016, an over-allotment option granted to the underwriters (the "Over-Allotment Option") to purchase up to an additional 16,050,000 common shares at a price of $9.35 per common share was exercised in full for additional gross proceeds of approximately $150 million, bringing the aggregate gross proceeds to approximately $1.15 billion ($1.13 billion of net cash proceeds). During the third quarter of 2016, Encana used a portion of the net proceeds from the 2016 Share Offering and divestitures to repay indebtedness under the Credit Facilities. Further information on the 2016 Share Offering can be found in Note 16 to the Consolidated Financial Statements included in Item 8 of this Annual Report on Form 10-K.

Dividends

Encana pays quarterly dividends to shareholders at the discretion of the Board of Directors.

($ millions, except as indicated)		**2018**		2017		2016
Dividend Payments	**$**	**57**	$	58	$	52
Dividend Payments ($/share)		**0.06**		0.06		0.06

On February 27, 2019, the Board of Directors declared a dividend of $0.01875 per common share payable on March 29, 2019 to common shareholders of record as of March 15, 2019. Common shares issued in conjunction with the Newfield acquisition are eligible to receive the dividend declared on February 27, 2019.

The dividends paid in 2018 included $1 million (2017 - $1 million; 2016 - $1 million) in common shares issued in lieu of cash dividends under Encana's Dividend Reinvestment Plan ("DRIP"). On February 28, 2019, the Company announced the suspension of its DRIP effective immediately.

Normal Course Issuer Bid

On February 13, 2019, the Company confirmed it will proceed with its previously announced plans to spend up to $1.25 billion to purchase common shares, for cancellation, subject to the receipt of regulatory approvals. On February 27, 2019, the Company announced that the TSX accepted its notice of intention to commence a NCIB beginning March 4, 2019 and ending March 3, 2020.

On February 26, 2018, Encana received approval from the TSX to commence a NCIB that enabled the Company to purchase, for cancellation, up to 35 million common shares over a 12-month period from February 28, 2018 to February 27, 2019. Under this NCIB program, the Company used cash on hand to purchase approximately 20.7 million common shares for total consideration of approximately $250 million in 2018. For additional information on the Company's 2018 NCIB program, refer to Note 16 to the Consolidated Financial Statements included in Item 8 of this Annual Report on Form 10-K.

Off-Balance Sheet Arrangements

The Company may enter into off-balance sheet arrangements and transactions that can give rise to material off-balance sheet obligations. Encana's material off-balance sheet arrangements include transportation and processing agreements, drilling rig commitments, and building leases, as outlined in the Contractual Obligations table below, as well as undrawn letters of credit, all of which are customary agreements in the oil and gas industry. Other than the items discussed above, there are no other transactions, arrangements, or relationships with unconsolidated entities or persons that are reasonably likely to materially affect the Company's liquidity or the availability of, or requirements for, capital resources.

Contractual Obligations

Contractual obligations arising from long-term debt, capital leases, risk management liabilities, asset retirement obligations and The Bow office building are recognized on the Company's Consolidated Balance Sheet. The following table outlines the Company's undiscounted obligations and commitments at December 31, 2018:

	Expected Future Payments				
($ millions)	2019	2020-2021	2022-2023	Thereafter	Total
Long-Term Debt	$ 500	$ 600	$ -	$ 3,111	**$ 4,211**
Interest Payments on Long-Term Debt	251	469	422	2,335	**3,477**
Capital Leases	84	172	12	27	**295**
Interest Payments on Capital Leases	15	14	4	3	**36**
Risk Management Liabilities	26	22	-	-	**48**
Asset Retirement Obligation	91	197	56	1,027	**1,371**
The Bow Office Building	11	27	32	437	**507**
Interest Payments on The Bow Office Building	59	116	113	681	**969**
Obligations	1,037	1,617	639	7,621	**10,914**
Transportation and Processing	685	1,259	1,008	2,220	**5,172**
Drilling and Field Services	128	44	-	-	**172**
Building Leases	17	32	31	35	**115**
Commitments	830	1,335	1,039	2,255	**5,459**
Total Contractual Obligations	$ 1,867	$ 2,952	$ 1,678	$ 9,876	**$ 16,373**
The Bow Office Building Sublease Recoveries	$ (35)	$ (70)	$ (71)	$ (550)	**$ (726)**

Interest Payments on Long-Term Debt, Capital Leases and The Bow Office Building represent scheduled cash payments on the respective obligations. Further information can be found in Notes 13 and 14 to the Consolidated Financial Statements included in Item 8 of this Annual Report on Form 10-K.

Capital Leases relates to an office building and the obligation related to the Deep Panuke Production Field Centre. Further information can be found in Note 14 to the Consolidated Financial Statements included in Item 8 of this Annual Report on Form 10-K.

Risk Management Liabilities represents Encana's net liability position with counterparties. Further information can be found in Note 23 to the Consolidated Financial Statements included in Item 8 of this Annual Report on Form 10-K.

Asset Retirement Obligation represents estimated costs arising from the obligation to fund the disposal of long-lived assets upon their abandonment. The majority of Encana's asset retirement obligations relate to the plugging of wells and related abandonment of oil and gas properties including an offshore production platform, processing plants and land or seabed restoration. Revisions to estimated retirement obligations can result from changes in regulatory requirements, changes in retirement cost estimates, revisions to estimated inflation rates and estimated timing of abandonment. Further information can be found in Note 15 to the Consolidated Financial Statements included in Item 8 of this Annual Report on Form 10-K.

The Bow Office Building relates to the 25-year lease agreement with a third-party developer that commenced in 2012. Encana has recognized the accumulated construction costs for The Bow office building as an asset with a related liability. At the conclusion of the 25-year term, the remaining asset and corresponding liability are expected to be derecognized. Encana has subleased approximately 50 percent of The Bow office space under the lease agreement. The Bow Office Building Sublease Recoveries in the table above include the amounts expected to be recovered from the sublease. Further information can be found in Note 14 to the Consolidated Financial Statements included in Item 8 of this Annual Report on Form 10-K.

Transportation and Processing commitments relate to contractual obligations for capacity rights with third-party pipelines and processing facilities. Drilling and Field Services commitments represent minimum future expenditures for drilling, well servicing and equipment commitment rights. Significant development commitments with joint venture partners are partially satisfied by Commitments included in the table above. Building Leases consist of various building leases used in Encana's daily operations.

Further to the commitments disclosed above, Encana also has various obligations that become payable if certain events occur including variable interests arising from gathering and compression agreements and guarantees on transportation commitments resulting from completed property divestitures as described in Notes 18, 23 and 25, respectively, to the Consolidated Financial Statements included in Item 8 of this Annual Report on Form 10-K.

In addition, Encana has purchase orders for the purchase of inventory and other goods and services, which typically represent authorization to purchase rather than binding agreements. Encana also has obligations to fund its defined benefit pension and other post-employment benefit plans, as well as unrecognized tax benefits where the settlement is not expected within the next 12 months as described in Notes 21 and 6, respectively, to the Consolidated Financial Statements included in Item 8 of this Annual Report on Form 10-K.

Encana may have potential exposures related to previously divested properties where the purchasers typically assume all obligations to plug, abandon, and decommission the associated wells, structures, and facilities acquired. One or more of the counterparties in these transactions could, either as a result of the severe decline in oil and natural gas prices or other factors related to the historical or future operations of their respective businesses, face financial problems that may have a significant impact on their solvency and ability to continue as a going concern. If a purchaser becomes the subject of a proceeding under relevant insolvency laws or otherwise fails to perform required abandonment obligations, Encana could be required to perform such actions under applicable federal laws and regulations. While the Company believes that the risk of such event occurring is low, the Company could be forced to use available cash to cover the costs of such liabilities and obligations should they arise.

Contingencies

For information on contingencies, refer to Note 25 to the Consolidated Financial Statements included in Item 8 of this Annual Report on Form 10-K.

Accounting Policies and Estimates

Critical Accounting Estimates

The preparation of financial statements in accordance with U.S. GAAP requires management to make informed judgments and estimates that affect the reported amounts of assets, liabilities, revenues, and expenses. For a discussion of the Company's significant accounting policies refer to Note 1 to the Consolidated Financial Statements included in Item 8 of this Annual Report on Form 10-K. Changes in facts and circumstances or additional information may result in revised estimates, and actual results may differ from these estimates. Management considers the following to be its most critical accounting estimates that involve judgment. The following discussion outlines the accounting policies and practices involving the use of estimates that are critical to determining Encana's financial results. Changes in the estimates and assumptions discussed below could materially affect the amount or timing of the financial results of the Company.

Description	Judgments and Uncertainties
Upstream Assets and Reserve Estimates	
As Encana follows full cost accounting for oil, NGL and natural gas activities, reserves estimates are a key input to the Company's depletion, gain or loss on divestitures and ceiling test impairment calculations. In addition, these reserves are the basis for the Company's supplemental oil and gas disclosures.	Due to the inter-relationship of various judgments made to reserve estimates and the volatile nature of commodity prices, it is generally not possible to predict the timing or magnitude of ceiling test impairments.
Encana estimates its proved oil and gas reserves according to the definition of proved reserves provided by the SEC. The Company's estimates of proved reserves are made using available geological and reservoir data as well as production performance data and must demonstrate with reasonable certainty to be economically producible in future periods from known reservoirs under existing economic conditions, operating methods and government regulations. The estimation of reserves is a subjective process.	Revisions to reserve estimates are necessary due to changes in and among other things, development plans, projected future rates of production, the timing of future expenditures, reservoir performance, economic conditions, governmental restrictions as well as changes in the expected recovery associated with infill drilling, all of which are subject to numerous uncertainties and various interpretations. Downward revisions in proved reserve estimates due to changes in reserve estimates may increase depletion expense and may also result in a ceiling test impairment.
Reserves are calculated using an unweighted arithmetic average of commodity prices in effect on the first day of each of the previous 12 months, held flat for the life of the production, except where prices are defined by contractual arrangements.	Decreases in prices may result in reductions in certain proved reserves due to reaching economic limits at an earlier projected date and impact earnings through depletion expense and ceiling test impairments.
Encana manages its business using estimates of reserves and resources based on forecast prices and costs as it gives consideration to probable and possible reserves and future changes in commodity prices.	Encana believes that the discounted after-tax future net cash flows from proved reserves required to be used in the ceiling test calculation are not indicative of the fair market value of Encana's oil and natural gas properties or the future net cash flows expected to be generated from such properties.
Business Combinations	
Encana follows the acquisition method of accounting for business combinations. Assets acquired and liabilities assumed are recognized at the date of acquisition at their respective estimated fair values. Any excess of the purchase price over the fair value amounts assigned to assets and liabilities is recorded as goodwill. Any deficiency of the purchase price over the estimated fair values of the net assets acquired is recorded as a gain in net earnings.	The most significant assumptions relate to the estimated fair values assigned to proved and unproved oil and natural gas properties. The assumptions made in performing these valuations include discount rates, future commodity prices and costs, the timing of development activities, projections of oil and gas reserves, estimates to abandon and reclaim producing wells and tax amortization benefits available to a market participant. Changes in key assumptions may cause the acquisition accounting to be revised, including the recognition of additional goodwill or discount on acquisition. There is no assurance the underlying assumptions or estimates associated with the valuation will occur as initially expected.
Fair value estimates are determined based on information that existed at the time of the acquisition, utilizing expectations and assumptions that would be available to and made by a market participant. When market-observable prices are not available to value assets and liabilities, the Company may use the cost, income, or market valuation approaches depending on the quality of information available to support management's assumptions.	Estimated fair values assigned to assets acquired can have a significant effect on results of operations in the future through impairments of goodwill. In addition, differences between the future commodity prices when acquiring assets and the historical 12-month average trailing price to calculate ceiling test impairments of upstream assets may impact net earnings.

Description	Judgments and Uncertainties
Goodwill Impairments	
Goodwill is assessed for impairment at least annually in December, at the reporting unit level which are Encana's country cost centres. To assess whether goodwill is impaired, the carrying amount of each reporting unit is determined and compared to the fair value of the reporting unit. If the carrying amount of the reporting unit is higher than its related fair value, then goodwill is measured and written down to the reporting unit's implied fair value of goodwill. The implied fair value of goodwill is determined by deducting the fair value of the reporting unit's assets and liabilities from the fair value of the reporting unit as if the reporting entity had been acquired in a business combination. Any excess of the carrying value of goodwill over the implied fair value of goodwill is recognized as an impairment and charged to net earnings.	The most significant assumptions used to determine a reporting unit's fair value include estimations of oil and natural gas reserves, including both proved reserves and risk-adjusted unproved reserves, estimates of market prices considering forward commodity price curves as of the measurement date, market discount rates and estimates of operating, administrative, and capital costs adjusted for inflation. In addition, management may support fair value estimates determined with comparable companies that are actively traded in the public market, recent comparable asset transactions, and transaction premiums. This would require management to make certain judgments about the selection of comparable companies utilized.
Because quoted market prices for the Company's reporting units are not available, management applies judgment in determining the estimated fair value of reporting units for purposes of performing goodwill impairment tests. Encana may use a combination of the income and the market valuation approaches.	Downward revisions of estimated reserves quantities, increases in future cost estimates, sustained decreases in oil or natural gas prices, or divestiture of a significant component of the reporting unit could reduce expected future cash flows and fair value estimates of the reporting units and possibly result in an impairment of goodwill in future periods.
Encana has assessed its goodwill for impairment at December 31, 2018 and no impairment was recognized as there were no indicators of impairment. The reporting units' fair values were substantially in excess of the carrying values and as a result was not at risk of failing step one of the impairment test as at December 31, 2018.	
Asset Retirement Obligation	
Asset retirement obligations are those legal obligations where the Company will be required to retire tangible long-lived assets such as producing well sites, an offshore production platform, processing plants, and restoring land or seabed at the end of oil and gas production operations. The fair value of estimated asset retirement obligations is recognized on the Consolidated Balance Sheet when incurred and a reasonable estimate of fair value can be made. The asset retirement cost, equal to the initially estimated fair value of the asset retirement obligation, is capitalized as part of the cost of the related long-lived asset. Changes in the estimated obligation are recognized as a change in the asset retirement obligation and the related asset retirement cost. Actual expenditures incurred are charged against the accumulated asset retirement obligation. Accretion expense is recognized over time as the discounted liability is accreted to its expected settlement value.	Asset removal technologies and costs are constantly changing, as are regulatory, political, environmental, safety, and public relations considerations. The asset retirement obligation is estimated by discounting the expected future cash flows of the settlement. The discounted cash flows are based on estimates of such factors as reserves lives, retirement costs, timing of settlements, credit-adjusted risk-free rates and inflation rates. Changes in these estimates impact net earnings through accretion of the asset retirement obligation in addition to depletion of the asset retirement cost included in property, plant and equipment.
Derivative Financial Instruments	
Encana uses derivative financial instruments to manage its exposure to market risks relating to commodity prices, foreign currency exchange rates and interest rates. The Company's policy is not to utilize derivative financial instruments for speculative purposes. Realized gains or losses from financial derivatives are recognized in net earnings as the contracts are settled. Unrealized gains and losses are recognized in net earnings at the end of each respective reporting period based on the changes in fair value of the contracts.	Encana's derivative financial instruments primarily relate to commodities including oil, NGLs, natural gas and power. The most significant assumptions used in determining the fair value to the Company's commodity derivatives financial instruments include estimates of future commodity prices, implied volatilities of commodity prices, discount rates and estimates of counterparty credit risk. These pricing and discounting variables are sensitive to the period of the contract and market volatility as well as regional price differentials. Changes in these estimates and assumptions can impact net earnings through decreased revenues or increased expenses.
Derivative financial instruments are measured at fair value with changes in fair value recognized in net earnings. Fair value estimates are determined using quoted prices in active markets, inferred based on market prices of similar assets and liabilities or valued using internally developed estimates. The Company may use various valuation techniques including the discounted cash flow or option valuation models.	
As Encana has chosen not to elect hedge accounting treatment for the Company's derivative financial instruments, changes in the fair values of derivative financial instruments can have a significant impact on Encana's results of operations. Generally, changes in fair values of derivative financial instruments do not impact the Company's liquidity or capital resources. Settlements of derivative financial instruments do have an impact on the Company's liquidity and results of operation.	

Description	Judgments and Uncertainties
Income Taxes	
Encana follows the liability method of accounting for income taxes. Under this method, deferred income taxes are recorded for the effect of any temporary difference between the accounting and income tax basis of an asset or liability, using the enacted income tax rates and laws expected to apply when the assets are realized and liabilities are settled. Current income taxes are measured at the amount expected to be recoverable from or payable to the taxing authorities based on the income tax rates and laws enacted at the end of the reporting period. The effect of a change in the enacted tax rates or laws is recognized in net earnings in the period of enactment.	Tax interpretations, regulations and legislation, including U.S. Tax Reform, and potential Treasury Department regulations and guidance, in the various jurisdictions in which the Company and its subsidiaries operate are subject to change and interpretation. As such, income taxes are subject to measurement uncertainty and the interpretations can impact net earnings through the income tax expense arising from the changes in deferred income tax assets or liabilities.
Deferred income tax assets are routinely assessed for realizability. If it is more likely than not that deferred tax assets will not be realized, a valuation allowance is recorded to reduce the deferred tax assets.	Encana considers available positive and negative evidence when assessing the realizability of deferred tax assets, including historic and expected future taxable earnings, available tax planning strategies and carry forward periods. Numerous judgments and assumptions are inherent in the determination of future taxable income, including factors such as future operating conditions, particularly related to oil and gas prices. As a result, the assumptions used in determining expected future taxable earnings are consistent with those used in the goodwill impairment assessment.
Encana's interim income tax expense is determined using an estimated annual effective income tax rate applied to year-to-date net earnings before income tax plus the effect of legislative changes and amounts in respect of prior periods.	The estimated annual effective income tax rate is impacted by expected annual earnings, statutory rate and other foreign differences, non-taxable capital gains and losses, tax differences on divestitures and transactions, and partnership tax allocations in excess of funding.
Encana recognizes the financial statement effects of a tax position when it is more likely than not, based on the technical merits, that the position will be sustained upon examination by a taxing authority. A recognized tax position is initially and subsequently measured as the largest amount of tax benefit that is greater than 50 percent likely of being realized upon settlement with a taxing authority. Liabilities for unrecognized tax benefits that are not expected to be settled within the next 12 months are included in other liabilities and provisions.	The Company routinely assesses potential uncertain tax positions and, if required, establishes accruals for such amounts. The accruals are adjusted based on changes in facts and circumstances. Material changes to Encana's income tax accruals may occur in the future based on the progress of ongoing audits, changes in legislation or resolution of pending matters.
Encana's unremitted earnings from its foreign subsidiaries are considered to be permanently reinvested outside of Canada, as a result the Company does not calculate a deferred tax liability for Canadian income taxes on these earnings.	Determination of unrecognized deferred income tax liabilities is not practicable due to the significant uncertainty in assumptions that would be required including determining the nature of any future remittances, that could be distributions in the form of non-taxable returns of capital or taxable earnings and associated withholding taxes, or determining the tax rates on any future remittances that could vary significantly depending on the available approaches to repatriate the earnings.

Recent Accounting Pronouncements

For recently issued accounting policies, refer to Note 1 to the Consolidated Financial Statements included in Item 8 of this Annual Report on Form 10-K.

Non-GAAP Measures

Certain measures in this document do not have any standardized meaning as prescribed by U.S. GAAP and, therefore, are considered non-GAAP measures. These measures may not be comparable to similar measures presented by other issuers and should not be viewed as a substitute for measures reported under U.S. GAAP. These measures are commonly used in the oil and gas industry and by Encana to provide shareholders and potential investors with additional information regarding the Company's liquidity and its ability to generate funds to finance its operations. Non-GAAP measures include: Non-GAAP Cash Flow, Non-GAAP Cash Flow Margin, Debt to Adjusted Capitalization and Net Debt to Adjusted EBITDA. Management's use of these measures is discussed further below.

Non-GAAP Cash Flow and Non-GAAP Cash Flow Margin

Non-GAAP Cash Flow is a non-GAAP measure defined as cash from (used in) operating activities excluding net change in other assets and liabilities, net change in non-cash working capital and current tax on sale of assets.

Non-GAAP Cash Flow Margin is a non-GAAP measure defined as Non-GAAP Cash Flow per BOE of production.

Management believes these measures are useful to the Company and its investors as a measure of operating and financial performance across periods and against other companies in the industry, and are an indication of the Company's ability to generate cash to finance capital programs, to service debt and to meet other financial obligations. These measures are used, along with other measures, in the calculation of certain performance targets for the Company's management and employees.

($ millions, except as indicated)	**2018**	2017	2016
Cash From (Used in) Operating Activities	**$ 2,300**	$ 1,050	$ 625
(Add back) deduct:			
Net change in other assets and liabilities	**(60)**	(40)	(26)
Net change in non-cash working capital	**245**	(253)	(187)
Current tax on sale of assets	**-**	-	-
Non-GAAP Cash Flow	**$ 2,115**	$ 1,343	$ 838
Production Volumes (MMBOE)	**131.8**	114.3	129.1
Non-GAAP Cash Flow Margin ($/BOE)	**$ 16.05**	$ 11.75	$ 6.49

Debt to Adjusted Capitalization

Debt to Adjusted Capitalization is a non-GAAP measure which adjusts capitalization for historical ceiling test impairments that were recorded as at December 31, 2011. Management monitors Debt to Adjusted Capitalization as a proxy for Encana's financial covenant under the Credit Facilities which require debt to adjusted capitalization to be less than 60 percent. Adjusted Capitalization includes debt, total shareholders' equity and an equity adjustment for cumulative historical ceiling test impairments recorded as at December 31, 2011 in conjunction with the Company's January 1, 2012 adoption of U.S. GAAP.

($ millions, except as indicated)	**December 31, 2018**	December 31, 2017	December 31, 2016
Long-Term Debt, including current portion	**$ 4,198**	$ 4,197	$ 4,198
Total Shareholders' Equity	**7,447**	6,728	6,126
Equity Adjustment for Impairments at December 31, 2011	**7,746**	7,746	7,746
Adjusted Capitalization	**$ 19,391**	$ 18,671	$ 18,070
Debt to Adjusted Capitalization	**22%**	22%	23%

Net Debt to Adjusted EBITDA

Net Debt to Adjusted EBITDA is a non-GAAP measure whereby Net Debt is defined as long-term debt, including the current portion, less cash and cash equivalents and Adjusted EBITDA is defined as trailing 12-month net earnings (loss) before income taxes, DD&A, impairments, accretion of asset retirement obligation, interest, unrealized gains/losses on risk management, foreign exchange gains/losses, gains/losses on divestitures and other gains/losses.

Management believes this measure is useful to the Company and its investors as a measure of financial leverage and the Company's ability to service its debt and other financial obligations. This measure is used, along with other measures, in the calculation of certain financial performance targets for the Company's management and employees.

($ millions, except as indicated)	**December 31, 2018**	December 31, 2017	December 31, 2016
Long-Term Debt, including current portion	**$ 4,198**	$ 4,197	$ 4,198
Less:			
Cash and cash equivalents	**1,058**	719	834
Net Debt	**3,140**	3,478	3,364
Net Earnings (Loss)	**1,069**	827	(944)
Add back (deduct):			
Depreciation, depletion and amortization	**1,272**	833	859
Impairments	**-**	-	1,396
Accretion of asset retirement obligation	**32**	37	51
Interest	**351**	363	397
Unrealized (gains) losses on risk management	**(519)**	(442)	614
Foreign exchange (gain) loss, net	**168**	(279)	(210)
(Gain) loss on divestitures, net	**(5)**	(404)	(390)
Other (gains) losses, net	**17**	(42)	(58)
Income tax expense (recovery)	**94**	603	(676)
Adjusted EBITDA	**$ 2,479**	$ 1,496	$ 1,039
Net Debt to Adjusted EBITDA (times)	**1.3**	2.3	3.2