2018
Q3 REPORT

For the period ended
September 30, 2018

encana

Encana delivers strong third quarter financial and operational performance; significant liquids growth driving margin expansion and returns

Calgary, Alberta (November 1, 2018) **TSX, NYSE: ECA**

Encana delivered strong financial performance in the third quarter driven by significant liquids growth, high realized pricing and continued efficiencies. Financial and operating highlights from the quarter include:

- net earnings of $39 million
- cash from operating activities of $885 million, up 148 percent year-over-year
- non-GAAP free cash flow of $66 million; company is on track to generate full-year non-GAAP free cash flow in 2018, one year earlier than expected in its five-year plan
- non-GAAP cash flow of $589 million, up 118 percent year-over-year
- non-GAAP cash flow margin of $16.93 per barrel of oil equivalent (BOE), up 64 percent year-over-year; company expects full-year average non-GAAP cash flow margin of more than $16 per BOE
- liquids production of 178,700 barrels per day (bbls/d), up 40 percent year-over-year and 15 percent from the previous quarter; liquids made up 47 percent of total third quarter production and 46 percent year-to-date, with high-value oil and condensate making up more than 75 percent of total liquids volumes
- total production of 378,200 barrels of oil equivalent per day (BOE/d), up 33 percent year-over-year
- Permian production up 54 percent year-over-year to 98,500 BOE/d; current production over 100,000 BOE/d
- Montney liquids volumes up 151 percent year-over-year and on track with fourth quarter target of 55,000 bbls/d to 65,000 bbls/d; current liquids production about 55,000 bbls/d
- operational efficiencies, such as decreased drilling and completion cycle times, along with proactive supply chain management, continuing to largely offset inflation with upstream operating expense and transportation and processing costs down 10 percent and nine percent respectively from the second quarter
- announced agreement to sell San Juan assets for approximately $480 million on October 1

Operational performance: Core assets delivering non-GAAP free operating cash flow

Permian: Cube development delivering efficient execution with record production

- total production of 98,500 BOE/d, including 61,900 bbls/d of oil, up 54 and 60 percent respectively year-over-year
- current production exceeding 100,000 BOE/d
- strong performance from three Midland County cubes delivering an average 30-day initial production rate of 1,475 BOE/d including 1,200 bbls/d of oil
- operational efficiencies, including use of local sand and recycled water, continue to offset inflation

Montney: Liquids-focused program delivering high-value growth

- liquids production of 44,200 bbls/d, up 151 percent year-over-year and 23 percent from the second quarter; total production of 200,600 BOE/d
- current liquids production of about 55,000 bbls/d; on track to deliver fourth quarter liquids production between 55,000 and 65,000 bbls/d
- Pipestone Liquids Hub online in September, ahead of schedule, supporting condensate growth plan
- lowered Pipestone drilling and completion costs by 25 percent compared to 2017 average

Eagle Ford and Duvernay: Delivering high return growth

- combined production of 65,800 BOE/d, up 12 percent from second quarter
- strong results from Graben wells in Eagle Ford with average 30-day initial production rates of 1,200 BOE/d, with about 90 percent being oil
- Eagle Ford continues to deliver highest margin production in the portfolio

Market diversification: Maximizing realized pricing and ensuring efficient market access
Through a combination of pipeline transportation and term financial basis hedging, Encana has limited its exposure to Midland oil pricing and AECO gas pricing. Including basis hedges, the company's third quarter Permian realized oil price was 101 percent of the WTI average while Canadian realized gas prices were 86 percent of the NYMEX average.

As at September 30, 2018, Encana has hedged approximately 136,500 bbls/d of expected oil and condensate production and 1,017 million cubic feet per day (MMcf/d) of expected natural gas production for the remainder of 2018, using a variety of structures.

Corporate Guidance
Encana adjusted its Corporate Guidance, lowering its expected transportation and processing costs to between $7.20 and $7.40 per BOE for a reduction of about $25 million. In addition, the company updated its expected capital investment to approximately $2.0 billion, which includes current-year expenditures on the Pipestone Liquids Hub and the San Juan assets totaling approximately $55 million as well as modest pressure on diesel fuel costs and steel tariffs.

Dividend Declared
On October 31, 2018, the Board of Directors declared a dividend of $0.015 per common share payable on December 31, 2018 to common shareholders of record as of December 14, 2018.

Third Quarter Highlights

Production summary			
(for the period ended September 30) (average)	**Q3 2018**	Q3 2017	% Δ
Oil (Mbbls/d)	**95.5**	75.2	27
NGLs – Plant Condensate (Mbbls/d)	**41.0**	27.9	47
NGLs – Other (Mbbls/d)	**42.2**	24.4	73
Oil and NGLs Total (Mbbls/d)	**178.7**	127.5	40
Natural gas (MMcf/d)	**1,197**	939	27
Total production (MBOE/d)	**378.2**	284.0	33

Liquids and natural gas prices		
	Q3 2018	Q3 2017
Liquids ($/bbl)		
WTI	**69.50**	48.21
Encana realized liquids prices[1]	**49.05**	41.86
Oil	**57.05**	47.78
NGLs – Plant Condensate	**52.89**	45.84
NGLs – Other	**27.23**	19.00
Natural gas		
NYMEX ($/MMBtu)	**2.90**	3.00
Encana realized natural gas price[1] ($/Mcf)	**2.50**	2.23

[1] Prices include the impact of realized gain (loss) on risk management.

Non-GAAP Cash Flow Reconciliation		
(for the period ended September 30) ($ millions, except as indicated)	**Q3 2018**	Q3 2017
Cash from (used in) operating activities	**885**	357
Deduct (add back):		
Net change in other assets and liabilities	**(17)**	(11)
Net change in non-cash working capital	**313**	98
Current tax on sale of assets	**-**	-
Non-GAAP cash flow[1]	**589**	270
Divided by Production Volumes (MMBOE)	**34.8**	26.1
Non-GAAP cash flow margin[1] ($/BOE)	**16.93**	10.34
Non-GAAP Free Cash Flow Reconciliation		
Non-GAAP cash flow[1]	**589**	270
Less capital expenditures	**(523)**	(473)
Non-GAAP free cash flow[1]	**66**	(203)
Non-GAAP Operating Earnings Reconciliation		
Net earnings (loss)	**39**	294
Before-tax (addition) deduction:		
Unrealized gain (loss) on risk management	**(164)**	(76)
Non-operating foreign exchange gain (loss)	**24**	203
Gain (loss) on divestiture	**-**	406
	(140)	533
Income tax	**16**	(263)
After-tax (addition) deduction	**(124)**	270
Non-GAAP operating earnings [1]	**163**	24

[1] Non-GAAP cash flow, non-GAAP cash flow margin, non-GAAP free cash flow and non-GAAP operating earnings (loss) are non-GAAP measures as defined in Note 1.

Third quarter conference call

A conference call and webcast to discuss the 2018 third quarter results will be held for the investment community today at 7 a.m. MT (9 a.m. ET). To participate, please dial 888-231-8191 (toll-free in North America) or 647-427-7450 (international) approximately 10 minutes prior to the conference call. The live audio webcast of the third quarter conference call, including slides, will also be available on Encana's website, www.encana.com, under Investors/Presentations & Events. The webcasts will be archived for approximately 90 days.

Encana Corporation

Encana is a leading North American energy producer that is focused on developing its strong portfolio of resource plays, held directly and indirectly through its subsidiaries, producing oil, natural gas liquids (NGLs) and natural gas. By partnering with employees, community organizations and other businesses, Encana contributes to the strength and sustainability of the communities where it operates. Encana common shares trade on the Toronto and New York stock exchanges under the symbol ECA.

Important Information

Encana reports in U.S. dollars unless otherwise noted. Production, sales and reserves estimates are reported on a net (after-royalties) basis, unless otherwise noted. The term liquids is used to represent oil, NGLs and condensate. The term liquids-rich is used to represent natural gas streams with associated liquids volumes. Unless otherwise specified or the context otherwise requires, references to Encana or to the company includes reference to subsidiaries of and partnership interests held by Encana Corporation and its subsidiaries.

NOTE 1: Non-GAAP measures

Certain measures in this news release 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 companies and should not be viewed as a substitute for measures reported under U.S. GAAP. For additional information regarding non-GAAP measures, see the Company's website. This news release contains references to non-GAAP measures as follows:

- **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. **Non-GAAP Free Cash Flow** is a non-GAAP measure defined as Non-GAAP Cash Flow in excess of capital investment, excluding net acquisitions and divestitures.

- **Non-GAAP Operating Earnings (Loss)** is a non-GAAP measure defined as net earnings (loss) excluding non-recurring or non-cash items that management believes reduces the comparability of the company's financial performance between periods. These items may include, but are not limited to, unrealized gains/losses on risk management, impairments, restructuring charges, non-operating foreign exchange gains/losses, gains/losses on divestitures and gains on debt retirement. Income taxes may include valuation allowances and the provision related to the pre-tax items listed, as well as income taxes related to divestitures and U.S. tax reform, and adjustments to normalize the effect of income taxes calculated using the estimated annual effective income tax rate.

ADVISORY REGARDING OIL AND GAS INFORMATION - The conversion of natural gas volumes to barrels of oil equivalent (BOE) is on the basis of six thousand cubic feet to one barrel. BOE is based on a generic energy equivalency conversion method primarily applicable at the burner tip and does not represent economic value equivalency at the wellhead. Readers are cautioned that BOE may be misleading, particularly if used in isolation. 30-day initial or peak production and other short-term rates are not necessarily indicative of long-term performance or of ultimate recovery.

ADVISORY REGARDING FORWARD-LOOKING STATEMENTS - This news release contains certain forward-looking statements or information (collectively, "FLS") within the meaning of applicable securities legislation, including the United States Private Securities Litigation Reform Act of 1995. FLS include: expectation of meeting or exceeding targets in corporate guidance and five-year plan; production growth, including from core assets, and commodity mix thereof; growth within cash flows; anticipated non-GAAP cash flow margin; ability to generate free cash flow; success of market diversification strategy and realized pricing; execution of strategy and future outlook in five-year plan, including expected growth, returns, free cash flow, capital allocation, operating efficiencies, projections based on commodity prices and use of cash therefrom; ability to offset cost inflation and anticipated efficiencies; ability to translate higher commodity prices into higher returns; focus on margin growth and quality returns; success and benefits of cube development model; expected capital program; number of well locations and anticipated development within five-year plan; anticipated hedging and outcomes of risk management program, including amount of hedged production; performance relative to peers; and anticipated dividends.

Readers are cautioned against unduly relying on FLS which, by their nature, involve numerous assumptions, risks and uncertainties that may cause such statements not to occur, or results to differ materially from those expressed or implied. These assumptions include: future commodity prices and differentials; foreign exchange rates; ability to access credit facilities and shelf prospectuses; assumptions contained in the Company's corporate guidance, five-year plan and as specified herein; data contained in key modeling statistics; availability of attractive hedges and enforceability of risk management program; effectiveness of Encana's drive to productivity and efficiencies; results from innovations; expectation that counterparties will fulfill their obligations under the gathering, midstream and marketing agreements; access to transportation and processing facilities where Encana operates; assumed tax, royalty and regulatory regimes; enforceability of transaction agreements; and expectations and projections made in light of, and generally consistent with, Encana's historical experience and its perception of historical trends, including with respect to the pace of technological development, benefits achieved and general industry expectations.

Risks and uncertainties that may affect these business outcomes include: ability to generate sufficient cash flow to meet obligations; commodity price volatility; ability to secure adequate transportation and potential pipeline curtailments; variability and discretion of Encana's board of directors to declare and pay dividends, if any; variability in the amount, number of shares and timing of purchases, if any, pursuant to the share repurchase program; timing and costs of well, facilities and pipeline construction; business interruption, property and casualty losses or unexpected technical difficulties, including impact of weather; counterparty and credit risk; impact of a downgrade in credit rating and its impact on access to sources of liquidity; fluctuations in currency and interest rates; risks inherent in Encana's corporate guidance; failure to achieve cost and efficiency initiatives; risks inherent in marketing operations; risks associated with technology; changes in or interpretation of royalty, tax, environmental, greenhouse gas, carbon, accounting and other laws or regulations; risks associated with existing and potential lawsuits and regulatory actions made against Encana; impact of disputes arising with its partners, including suspension of certain obligations and inability to dispose of assets or interests in certain arrangements; Encana's ability to acquire or find additional reserves; imprecision of reserves estimates and estimates of recoverable quantities of liquids and natural gas from plays and other sources not currently classified as proved, probable or possible reserves or economic contingent resources, including future net revenue estimates; risks associated with past and future acquisitions or divestitures of certain assets or other transactions or receipt of amounts contemplated under the transaction agreements (such transactions may include third-party capital investments, farm-outs or partnerships, which Encana may refer to from time to time as "partnerships" or "joint ventures" and the funds received in respect thereof which Encana may refer to from time to time as "proceeds", "deferred purchase price" and/or "carry capital", regardless of the legal form) as a result of various conditions not being met; and other risks and uncertainties impacting Encana's business, as described in its most recent Annual Report on Form 10-K and as described from time to time in Encana's other periodic filings as filed on SEDAR and EDGAR.

Although Encana believes the expectations represented by such FLS are reasonable, there can be no assurance that such expectations will prove to be correct. Readers are cautioned that the assumptions, risks and uncertainties referenced above are not exhaustive. FLS are made as of the date of this news release and, except as required by law, Encana undertakes no obligation to update publicly or revise any FLS. FLS contained in this news release are expressly qualified by these cautionary statements.

Further information on Encana Corporation is available on the company's website, www.encana.com, or by contacting:

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SOURCE: Encana Corporation

UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-Q

(Mark One)
[X] QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the quarterly period ended September 30, 2018

or

[ ] TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

Commission file number 1-15226

ENCANA CORPORATION
(Exact name of registrant as specified in its charter)

Canada	**98-0355077**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

Suite 4400, 500 Centre Street S.E., P.O. Box 2850, Calgary, Alberta, Canada, T2P 2S5
(Address of principal executive offices)

Registrant's telephone number, including area code **(403) 645-2000**

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes [X] No [ ]

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit such files). Yes [X] No [ ]

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, smaller reporting company, or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company," and "emerging growth company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer	[X]	Accelerated filer	[ ]
Non-accelerated filer	[ ]	Smaller reporting company	[ ]
		Emerging growth company	[ ]

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. [ ]

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).

Yes [ ] No [X]

Number of registrant's common shares outstanding as of October 26, 2018	952,478,421

ENCANA CORPORATION
FORM 10-Q
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DEFINITIONS

Unless the context otherwise indicates, references to “us,” “we,” “our,” “ours,” “Encana” and the “Company” refer to Encana Corporation and its consolidated subsidiaries. In addition, the following are other abbreviations and definitions of certain terms used within this Quarterly Report on Form 10-Q:

“AECO” means Alberta Energy Company and is the Canadian benchmark price for natural gas.

“ASU” means Accounting Standards Update.

“bbl” or “bbls” means barrel or barrels.

“BOE” means barrels of oil equivalent.

“Btu” means British thermal units, a measure of heating value.

“DD&A” means depreciation, depletion and amortization expenses.

“FASB” means Financial Accounting Standards Board.

“Mbbls/d” means thousand barrels per day.

“MBOE/d” means thousand barrels of oil equivalent per day.

“Mcf” means thousand cubic feet.

“MD&A” means Management’s Discussion and Analysis of Financial Condition and Results of Operations.

“MMBOE” means million barrels of oil equivalent.

“MMBtu” means million Btu.

“MMcf/d” means million cubic feet per day.

“NCIB” means normal course issuer bid.

“NGL” or “NGLs” means natural gas liquids.

“NYMEX” means New York Mercantile Exchange.

“OPEC” means Organization of the Petroleum Exporting Countries.

“SEC” means United States Securities and Exchange Commission.

“TSX” means Toronto Stock Exchange.

“U.S.”, “United States” or “USA” means United States of America.

“U.S. GAAP” means U.S. Generally Accepted Accounting Principles.

“WTI” means West Texas Intermediate.

CONVERSIONS

In this Quarterly Report on Form 10-Q, a conversion of natural gas volumes to BOE is on the basis of six Mcf to one bbl. BOE is based on a generic energy equivalency conversion method primarily applicable at the burner tip and does not represent economic value equivalency at the wellhead. Given that the value ratio based on the current price of oil as compared to natural gas is significantly different from the energy equivalency of 6:1, utilizing a conversion on a 6:1 basis may be misleading as an indication of value, particularly if used in isolation.

CONVENTIONS

Unless otherwise specified, all dollar amounts are expressed in U.S. dollars, all references to “dollars”, “$” or “US$” are to U.S. dollars and all references to “C$” are to Canadian dollars. All amounts are provided on a before tax basis, unless otherwise stated. In addition, all information provided herein is presented on an after royalties basis.

The term “liquids” is used to represent oil, NGLs and condensate. The term “liquids rich” is used to represent natural gas streams with associated liquids volumes. The term “play” is used to describe an area in which hydrocarbon accumulations or prospects of a given type occur. Encana’s focus of development is on hydrocarbon accumulations known to exist over a large areal expanse and/or thick vertical section and are developed using hydraulic fracturing. This type of development typically has a lower geological and/or commercial development risk and lower average decline rate, when compared to conventional development.

The term "core asset" refers to plays that are the focus of the Company's current capital investment and development plan. The Company continually reviews funding for development of its plays based on strategic fit, profitability and portfolio diversity and, as such, the composition of plays identified as a core asset may change over time.

References to information contained on the Company's website at www.encana.com are not incorporated by reference into, and does not constitute a part of, this Quarterly Report on Form 10-Q.

FORWARD-LOOKING STATEMENTS AND RISK

This Quarterly Report on Form 10-Q contains certain forward-looking statements or information (collectively, "forward-looking statements") within the meaning of applicable securities legislation, including the United States Private Securities Litigation Reform Act of 1995. Forward-looking statements include: composition of the Company's core assets, including allocation of capital and focus of development plans; growth in long-term shareholder value; vision of being a leading North American resource play company; statements with respect to the Company's strategic objectives including capital allocation strategy, focus of investment, growth of high margin liquids volumes, operating and capital efficiencies and ability to preserve balance sheet strength; ability to lower costs and improve efficiencies to achieve competitive advantage; ability to repeat and deploy successful practices across the Company's multi-basin portfolio; balancing commodity portfolio; anticipated commodity prices; success of and benefits from technology and innovation, including cube development approach and advanced completion designs; ability to optimize well and completion designs; future well inventory; anticipated drilling, number of drilling rigs and the success thereof; anticipated drilling costs and cycle times; anticipated proceeds and future benefits from various joint venture, partnership and other agreements; expected timing for construction of facilities and costs thereof; expansion of future midstream services; estimates of reserves and resources; expected production and product types; statements regarding anticipated cash flow, non-GAAP cash flow margin and leverage ratios; anticipated cash and cash equivalents; anticipated hedging and outcomes of risk management program, including exposure to certain commodity prices and foreign exchange, amount of hedged production, market access and physical sales locations; impact of changes in laws and regulations; compliance with environmental legislation and claims related to the purported causes and impact of climate change, and the costs therefrom; adequacy of provisions for abandonment and site reclamation costs; financial flexibility and discipline; ability to meet financial obligations, manage debt and financial ratios, finance growth and compliance with financial covenants; impact to the Company as a result of changes to its credit rating; access to the Company's credit facilities; planned annualized dividend and the declaration and payment of future dividends, if any; the Company's NCIB program, including amounts and number of shares to be acquired, anticipated timeframe, method and location of purchases, and source of funding thereof; adequacy of the Company's provision for taxes and legal claims; projections and expectation of meeting the targets contained in the Company's corporate guidance and five-year plan; ability to manage cost inflation and expected cost structures, including expected operating, transportation and processing and administrative expenses; competitiveness and pace of growth of the Company's assets within North America and against its peers; outlook of oil and gas industry generally and impact of geopolitical environment; expected future interest expense; the Company's commitments and obligations and anticipated payments thereunder; statements with respect to future ceiling test impairments; the possible impact and timing of accounting pronouncements, rule changes and standards; the timing of the closing of the sale of the Company's San Juan assets and the expectation that closing conditions and regulatory approvals in respect thereof will be satisfied; and the timing of the closing of the acquisition of Newfield and the expectation that closing conditions in respect thereof, including shareholder and regulatory approvals, will be satisfied.

Readers are cautioned against unduly relying on forward-looking statements which, by their nature, involve numerous assumptions, risks and uncertainties that may cause such statements not to occur, or results to differ materially from those expressed or implied. These assumptions include: future commodity prices and differentials; foreign exchange rates; ability to access credit facilities and shelf prospectuses; assumptions contained in the Company's corporate guidance, five-year plan and as specified herein; data contained in key modeling statistics; availability of attractive hedges and enforceability of risk management program; effectiveness of the Company's drive to productivity and efficiencies; results from innovations; expectation that counterparties will fulfill their obligations under the gathering, midstream and marketing agreements; access to transportation and processing facilities where Encana operates; assumed tax, royalty and regulatory regimes; and expectations and projections made in light of, and generally consistent with, Encana's historical experience and its perception of historical trends, including with respect to the pace of technological development, benefits achieved and general industry expectations.

Risks and uncertainties that may affect these business outcomes include: ability to generate sufficient cash flow to meet obligations; commodity price volatility; ability to secure adequate transportation and potential pipeline curtailments; variability and discretion of Encana's board of directors (the "Board of Directors") to declare and pay dividends, if any; timing and costs of well, facilities and pipeline construction; business interruption, property and casualty losses or unexpected technical difficulties, including impact of weather; counterparty and credit risk; impact of a downgrade in credit rating and its impact on access to sources of liquidity; fluctuations in currency and interest rates; risks inherent in the Company's corporate guidance; failure to achieve cost and efficiency initiatives; risks inherent in marketing operations; risks associated with technology; changes in or interpretation of royalty, tax, environmental, greenhouse gas, carbon, accounting and other laws or regulations; risks associated with existing and potential lawsuits and regulatory actions made against the Company; impact of disputes arising with its partners, including suspension of certain obligations and inability to dispose of assets or interests in certain arrangements; the Company's ability to acquire or find additional reserves; imprecision of reserves estimates and estimates of recoverable quantities, including future net revenue estimates; risks associated with past and future acquisitions or divestitures of certain assets or other transactions or receipt of amounts contemplated under the transaction agreements (such transactions may include third-party capital investments, farm-outs or partnerships, which Encana may refer to from time to time as "partnerships" or "joint ventures" and the funds received in respect thereof which Encana may refer to from time to time as "proceeds", "deferred purchase price" and/or "carry capital", regardless of the legal form) as a result of various conditions not being met; and other risks described herein and in Item 1A. Risk Factors of the Annual Report on Form 10-K for the fiscal year ended December 31, 2017 ("2017 Annual Report on Form 10-K") and risks and uncertainties impacting Encana's business as described from time to time in the Company's other periodic filings with the SEC.

Although the Company believes the expectations represented by such forward-looking statements are reasonable, there can be no assurance that such expectations will prove to be correct. Readers are cautioned that the assumptions, risks and uncertainties referenced above are not exhaustive. Forward-looking statements are made as of the date of this document and, except as required by law, the Company undertakes no obligation to update publicly or revise any forward-looking statements. The forward-looking statements contained in this Quarterly Report on Form 10-Q are expressly qualified by these cautionary statements.

The reader should read carefully the risk factors described herein and in Item 1A. Risk Factors of the 2017 Annual Report on Form 10-K for a description of certain risks that could, among other things, cause actual results to differ from these forward-looking statements.

PART I

Item 1. Financial Statements

Condensed Consolidated Statement of Earnings *(unaudited)*

(US$ millions, except per share amounts)		Three Months Ended September 30, 2018	Three Months Ended September 30, 2017 (1)	Nine Months Ended September 30, 2018	Nine Months Ended September 30, 2017 (1)
Revenues	*(Notes 3, 4)*				
Product and service revenues		**$ 1,488**	$ 880	**$ 4,025**	$ 2,751
Gains (losses) on risk management, net	*(Note 19)*	**(241)**	(35)	**(517)**	432
Sublease revenues		**15**	16	**50**	50
Total Revenues		**1,262**	861	**3,558**	3,233
Operating Expenses	*(Note 3)*				
Production, mineral and other taxes		**45**	27	**109**	80
Transportation and processing	*(Note 19)*	**278**	199	**799**	617
Operating	*(Notes 16, 17)*	**124**	132	**372**	377
Purchased product		**282**	202	**803**	565
Depreciation, depletion and amortization		**349**	210	**924**	590
Accretion of asset retirement obligation	*(Note 12)*	**8**	9	**24**	30
Administrative	*(Notes 16, 17)*	**57**	86	**187**	168
Total Operating Expenses		**1,143**	865	**3,218**	2,427
Operating Income (Loss)		**119**	(4)	**340**	806
Other (Income) Expenses					
Interest	*(Note 5)*	**92**	101	**265**	268
Foreign exchange (gain) loss, net	*(Notes 6, 19)*	**(23)**	(210)	**93**	(294)
(Gain) loss on divestitures, net	*(Note 8)*	**-**	(406)	**(4)**	(405)
Other (gains) losses, net	*(Note 17)*	**5**	(11)	**2**	(46)
Total Other (Income) Expenses		**74**	(526)	**356**	(477)
Net Earnings (Loss) Before Income Tax		**45**	522	**(16)**	1,283
Income tax expense (recovery)	*(Note 7)*	**6**	228	**(55)**	227
Net Earnings (Loss)		**$ 39**	$ 294	**$ 39**	$ 1,056
Net Earnings (Loss) per Common Share					
Basic & Diluted	*(Note 13)*	**$ 0.04**	$ 0.30	**$ 0.04**	$ 1.09
Dividends Declared per Common Share	*(Note 13)*	**$ 0.015**	$ 0.015	**$ 0.045**	$ 0.045
Weighted Average Common Shares Outstanding (millions)					
Basic & Diluted	*(Note 13)*	**955.1**	973.1	**962.2**	973.1

(1) 2017 revenues have been realigned to conform with the January 1, 2018 adoption of ASU 2014-09 "Revenue from Contracts with Customers".

Condensed Consolidated Statement of Comprehensive Income *(unaudited)*

(US$ millions)		Three Months Ended September 30, 2018	Three Months Ended September 30, 2017	Nine Months Ended September 30, 2018	Nine Months Ended September 30, 2017
Net Earnings (Loss)		**$ 39**	$ 294	**$ 39**	$ 1,056
Other Comprehensive Income (Loss), Net of Tax					
Foreign currency translation adjustment	*(Note 14)*	**22**	(97)	**21**	(172)
Pension and other post-employment benefit plans	*(Notes 14, 17)*	**-**	(1)	**(1)**	(2)
Other Comprehensive Income (Loss)		**22**	(98)	**20**	(174)
Comprehensive Income (Loss)		**$ 61**	$ 196	**$ 59**	$ 882

See accompanying Notes to Condensed Consolidated Financial Statements

Condensed Consolidated Balance Sheet *(unaudited)*

(US$ millions)		As at September 30, 2018	As at December 31, 2017
Assets			
Current Assets			
Cash and cash equivalents		**$ 615**	$ 719
Accounts receivable and accrued revenues		**835**	774
Risk management	*(Notes 18, 19)*	**146**	205
Income tax receivable		**290**	573
		1,886	2,271
Property, Plant and Equipment, at cost:	*(Note 9)*		
Oil and natural gas properties, based on full cost accounting			
Proved properties		**41,859**	40,228
Unproved properties		**3,964**	4,480
Other		**2,229**	2,302
Property, plant and equipment		**48,052**	47,010
Less: Accumulated depreciation, depletion and amortization		**(38,519)**	(38,056)
Property, plant and equipment, net	*(Note 3)*	**9,533**	8,954
Other Assets		**160**	144
Risk Management	*(Notes 18, 19)*	**132**	246
Deferred Income Taxes		**1,019**	1,043
Goodwill	*(Note 3)*	**2,588**	2,609
	(Note 3)	**$ 15,318**	$ 15,267
Liabilities and Shareholders' Equity			
Current Liabilities			
Accounts payable and accrued liabilities		**$ 1,751**	$ 1,415
Income tax payable		**1**	7
Risk management	*(Notes 18, 19)*	**450**	236
Current portion of long-term debt	*(Note 10)*	**500**	-
		2,702	1,658
Long-Term Debt	*(Note 10)*	**3,698**	4,197
Other Liabilities and Provisions	*(Note 11)*	**1,916**	2,167
Risk Management	*(Notes 18, 19)*	**68**	13
Asset Retirement Obligation	*(Note 12)*	**407**	470
Deferred Income Taxes		**33**	34
		8,824	8,539
Commitments and Contingencies	*(Note 21)*		
Shareholders' Equity			
Share capital - authorized unlimited common shares			
2018 issued and outstanding: 952.4 million shares (2017: 973.1 million shares)	*(Note 13)*	**4,655**	4,757
Paid in surplus		**1,358**	1,358
Accumulated deficit		**(581)**	(429)
Accumulated other comprehensive income	*(Note 14)*	**1,062**	1,042
Total Shareholders' Equity		**6,494**	6,728
		$ 15,318	$ 15,267

See accompanying Notes to Condensed Consolidated Financial Statements

Condensed Consolidated Statement of Changes in Shareholders' Equity *(unaudited)*

Nine Months Ended September 30, 2018 (US$ millions)		Share Capital	Paid in Surplus	Accumulated Deficit	Accumulated Other Comprehensive Income	Total Shareholders' Equity
Balance, December 31, 2017		**$ 4,757**	**$ 1,358**	**$ (429)**	**$ 1,042**	**$ 6,728**
Net Earnings (Loss)		**-**	**-**	**39**	**-**	**39**
Dividends on Common Shares	*(Note 13)*	**-**	**-**	**(43)**	**-**	**(43)**
Common Shares Purchased under Normal Course Issuer Bid	*(Note 13)*	**(102)**	**-**	**(148)**	**-**	**(250)**
Common Shares Issued Under Dividend Reinvestment Plan	*(Note 13)*	**-**	**-**	**-**	**-**	**-**
Other Comprehensive Income (Loss)	*(Note 14)*	**-**	**-**	**-**	**20**	**20**
Balance, September 30, 2018		**$ 4,655**	**$ 1,358**	**$ (581)**	**$ 1,062**	**$ 6,494**

Nine Months Ended September 30, 2017 (US$ millions)		Share Capital	Paid in Surplus	Accumulated Deficit	Accumulated Other Comprehensive Income	Total Shareholders' Equity
Balance, December 31, 2016		$ 4,756	$ 1,358	$ (1,198)	$ 1,210	$ 6,126
Net Earnings (Loss)		-	-	1,056	-	1,056
Dividends on Common Shares	*(Note 13)*	-	-	(44)	-	(44)
Common Shares Issued Under Dividend Reinvestment Plan	*(Note 13)*	1	-	-	-	1
Other Comprehensive Income (Loss)	*(Note 14)*	-	-	-	(174)	(174)
Balance, September 30, 2017		$ 4,757	$ 1,358	$ (186)	$ 1,036	$ 6,965

See accompanying Notes to Condensed Consolidated Financial Statements

Condensed Consolidated Statement of Cash Flows *(unaudited)*

(US$ millions)		Three Months Ended September 30, **2018**	2017	Nine Months Ended September 30, **2018**	2017
Operating Activities					
Net earnings (loss)		**$ 39**	$ 294	**$ 39**	$ 1,056
Depreciation, depletion and amortization		**349**	210	**924**	590
Accretion of asset retirement obligation	*(Note 12)*	**8**	9	**24**	30
Deferred income taxes	*(Note 7)*	**6**	227	**6**	283
Unrealized (gain) loss on risk management	*(Note 19)*	**164**	76	**422**	(396)
Unrealized foreign exchange (gain) loss	*(Note 6)*	**(23)**	(218)	**156**	(317)
Foreign exchange on settlements	*(Note 6)*	**(1)**	18	**(47)**	27
(Gain) loss on divestitures, net	*(Note 8)*	**-**	(406)	**(4)**	(405)
Other		**47**	60	**55**	31
Net change in other assets and liabilities		**(17)**	(11)	**(33)**	(27)
Net change in non-cash working capital	*(Note 20)*	**313**	98	**199**	(191)
Cash From (Used in) Operating Activities		**885**	357	**1,741**	681
Investing Activities					
Capital expenditures	*(Note 3)*	**(523)**	(473)	**(1,626)**	(1,287)
Acquisitions	*(Note 8)*	**(15)**	(2)	**(17)**	(50)
Proceeds from divestitures	*(Note 8)*	**24**	625	**89**	710
Net change in investments and other		**(8)**	14	**72**	93
Cash From (Used in) Investing Activities		**(522)**	164	**(1,482)**	(534)
Financing Activities					
Purchase of common shares	*(Note 13)*	**(50)**	-	**(250)**	-
Dividends on common shares	*(Note 13)*	**(14)**	(14)	**(43)**	(43)
Capital lease payments and other financing arrangements	*(Note 11)*	**(23)**	(21)	**(68)**	(61)
Cash From (Used in) Financing Activities		**(87)**	(35)	**(361)**	(104)
Foreign Exchange Gain (Loss) on Cash and Cash Equivalents Held in Foreign Currency		**3**	8	**(2)**	12
Increase (Decrease) in Cash and Cash Equivalents		**279**	494	**(104)**	55
Cash and Cash Equivalents, Beginning of Period		**336**	395	**719**	834
Cash and Cash Equivalents, End of Period		**$ 615**	$ 889	**$ 615**	$ 889
Cash, End of Period		**$ 30**	$ 39	**$ 30**	$ 39
Cash Equivalents, End of Period		**585**	850	**585**	850
Cash and Cash Equivalents, End of Period		**$ 615**	$ 889	**$ 615**	$ 889

See accompanying Notes to Condensed Consolidated Financial Statements

1. Basis of Presentation and Principles of Consolidation

Encana is in the business of the exploration for, the development of, and the production and marketing of oil, NGLs and natural gas.

The interim Condensed Consolidated Financial Statements include the accounts of Encana and entities in which it holds a controlling interest. All intercompany balances and transactions are eliminated on consolidation. Undivided interests in oil and natural gas exploration and production joint ventures and partnerships are consolidated on a proportionate basis. Investments in non-controlled entities over which Encana has the ability to exercise significant influence are accounted for using the equity method.

The interim Condensed Consolidated Financial Statements are prepared in conformity with U.S. GAAP and the rules and regulations of the SEC. Pursuant to these rules and regulations, certain information and disclosures normally required under U.S. GAAP have been condensed or have been disclosed on an annual basis only. Accordingly, the interim Condensed Consolidated Financial Statements should be read in conjunction with the annual audited Consolidated Financial Statements and the notes thereto for the year ended December 31, 2017, which are included in Item 8 of Encana's 2017 Annual Report on Form 10-K.

The interim Condensed Consolidated Financial Statements have been prepared following the same accounting policies and methods of computation as the annual audited Consolidated Financial Statements for the year ended December 31, 2017, except as noted below in Note 2. The disclosures provided below are incremental to those included with the annual audited Consolidated Financial Statements.

These unaudited interim Condensed Consolidated Financial Statements reflect, in the opinion of Management, all normal and recurring adjustments, with the exception of an out-of-period adjustment for the nine months ended September 30, 2017 as described in Note 6, which are necessary to present fairly the financial position and results of the Company as at and for the periods presented. Interim condensed consolidated financial results are not necessarily indicative of consolidated financial results expected for the fiscal year.

2. Recent Accounting Pronouncements

Changes in Accounting Policies and Practices

On January 1, 2018, Encana adopted the following ASUs issued by the FASB, which have not had a material impact on the Company's interim Condensed Consolidated Financial Statements:

- ASU 2014-09, "Revenue from Contracts with Customers" under Topic 606. The new standard replaces Topic 605, "Revenue Recognition" as well as other industry-specific guidance within the Accounting Standards Codification. Topic 606 is based on the principle that revenue is recognized on the transfer of promised goods or services to customers in an amount that reflects the consideration the company expects to be entitled to in exchange for those goods or services. The standard has been applied using the modified retrospective approach and did not have a material impact on the Company's Condensed Consolidated Financial Statements, other than enhancing disclosures related to the disaggregation of revenues from contracts with customers and performance obligations. The disclosures required under Topic 606 are included in Note 4, Revenues from Contracts with Customers.

- ASU 2017-07, "Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost". The amendment requires the service cost component to be presented with the related employee compensation costs, while the other components of net benefit costs are required to be presented separately from the service cost component and outside the subtotal of income from operations. In addition, the amendment allows only the service cost to be eligible for capitalization. The amendment has been applied retrospectively for the presentation of net periodic pension costs and net periodic postretirement benefit cost, whereas prospective adoption has been applied to the capitalization of the service cost component.

New Standards Issued Not Yet Adopted

- As of January 1, 2019, Encana will be required to adopt ASU 2016-02, "Leases" under Topic 842, which will replace Topic 840 "Leases". The new standard will require lessees to recognize right-of-use assets and related lease liabilities for all leases, including leases classified as operating leases, on the Consolidated Balance Sheet. However, Topic 842 provides a short-term lease exemption which does not require a right-of-use asset and lease liability to be recognized on the Consolidated Balance Sheet when the lease term is 12 months or less, including any renewal periods which are reasonably certain to be exercised. Encana intends to elect the short-term lease exemption. Topic 842 also expands disclosures related to the amount, timing and uncertainty of cash flows arising from leases.

  In July 2018, FASB issued ASU 2018-11, "Targeted Improvements", providing entities the option to apply Topic 842 at the adoption date recognizing a cumulative effect adjustment to the opening balance of retained earnings in the period of adoption, while the comparative periods presented would continue to be in accordance with Topic 840. Encana intends to elect this optional transition method, as well as certain practical expedients permitted under Topic 842, which will allow the Company to retain the classification of leases assessed under Topic 840 that commenced prior to adoption. Encana also intends to adopt the transitional practical expedient provided under ASU 2018-01, "Land Easement Practical Expedient for Transition to Topic 842" issued by FASB in January 2018. This amendment applies to land easements that existed or expired prior to adoption of Topic 842 and were not previously accounted for as leases under Topic 840. The expedient provides prospective application of Topic 842 to all new or modified land easements upon adoption of the new standard.

  Encana continues to review and analyze contracts, identify its portfolio of leased assets, gather the necessary terms and data elements, as well as identify the processes and controls required to support the accounting for leases and related disclosures. The Company is in the process of implementing and testing a lease software system which will facilitate the measurement and required disclosures for operating leases. The Company anticipates the software implementation to be complete by the end of 2018, at which time Encana expects to begin quantifying the impact of adopting Topic 842. Although Encana is not able to reasonably estimate the financial impact of Topic 842 at this time, the Company anticipates there will be an increase in right-of-use assets and lease liabilities on the Consolidated Balance Sheet.

- As of January 1, 2019, Encana will be required to adopt ASU 2018-02 "Reclassification of Certain Tax Effects from Accumulated Other Comprehensive Income". The amendments allow for a reclassification from accumulated other comprehensive income to retained earnings for stranded tax effects resulting from the Tax Cuts and Jobs Act ("U.S. Tax Reform"). Amendments can be applied either in the period of adoption or retrospectively to each period in which the effect of the rate change from the U.S. Tax Reform is recognized. While Encana has other post-employment benefit plans which were affected by the U.S. Tax Reform, the impact is not material to the Company's Consolidated Financial Statements. As a result, the Company does not intend to take the election provided in the amendment.

- As of January 1, 2020, Encana will be required to adopt ASU 2017-04, "Simplifying the Test for Goodwill Impairment". The amendment eliminates the second step of the goodwill impairment test which requires the Company to measure the impairment based on the excess amount of the carrying value of the reporting unit's goodwill over the implied fair value of its goodwill. Under this amendment, the goodwill impairment will be measured based on the excess amount of the reporting unit's carrying value over its respective fair value. The amendment will be applied prospectively at the date of adoption. Encana is currently in the early stages of reviewing the amendment, but does not expect the amendment to have a material impact on the Company's Consolidated Financial Statements.

3. Segmented Information

Encana's reportable segments are determined based on the Company's operations and geographic locations as follows:

- **Canadian Operations** includes the exploration for, development of, and production of oil, NGLs and natural gas and other related activities within the Canadian cost centre.
- **USA Operations** includes the exploration for, development of, and production of oil, NGLs and natural gas and other related activities within the U.S. cost centre.
- **Market Optimization** is primarily responsible for the sale of the Company's proprietary production. These results are reported in the Canadian and USA Operations. Market optimization activities include third party purchases and sales of product to provide operational flexibility and cost mitigation for transportation commitments, product type, delivery points and customer diversification. These activities are reflected in the Market Optimization segment. Market Optimization sells substantially all of the Company's upstream production to third party customers. Transactions between segments are based on market values and are eliminated on consolidation.

Corporate and Other mainly includes unrealized gains or losses recorded on derivative financial instruments. Once the instruments are settled, the realized gains and losses are recorded in the reporting segment to which the derivative instruments relate. Corporate and Other also includes amounts related to sublease rentals.

Results of Operations (For the three months ended September 30)

Segment and Geographic Information

	Canadian Operations		USA Operations		Market Optimization	
	2018	2017 (1)	**2018**	2017 (1)	**2018**	2017 (1)
Revenues						
Product and service revenues	**$ 453**	$ 235	**$ 718**	$ 421	**$ 317**	$ 224
Gains (losses) on risk management, net	**8**	25	**(84)**	16	**(1)**	-
Sublease revenues	**-**	-	**-**	-	**-**	-
Total Revenues	**461**	260	**634**	437	**316**	224
Operating Expenses						
Production, mineral and other taxes	**4**	6	**41**	21	**-**	-
Transportation and processing	**211**	138	**34**	31	**33**	30
Operating	**34**	36	**80**	81	**8**	11
Purchased product	**-**	-	**-**	-	**282**	202
Depreciation, depletion and amortization	**95**	53	**241**	139	**-**	1
Total Operating Expenses	**344**	233	**396**	272	**323**	244
Operating Income (Loss)	**$ 117**	$ 27	**$ 238**	$ 165	**$ (7)**	$ (20)

	Corporate & Other		Consolidated	
	2018	2017 (1)	**2018**	2017 (1)
Revenues				
Product and service revenues	**$ -**	$ -	**$ 1,488**	$ 880
Gains (losses) on risk management, net	**(164)**	(76)	**(241)**	(35)
Sublease revenues	**15**	16	**15**	16
Total Revenues	**(149)**	(60)	**1,262**	861
Operating Expenses				
Production, mineral and other taxes	**-**	-	**45**	27
Transportation and processing	**-**	-	**278**	199
Operating	**2**	4	**124**	132
Purchased product	**-**	-	**282**	202
Depreciation, depletion and amortization	**13**	17	**349**	210
Accretion of asset retirement obligation	**8**	9	**8**	9
Administrative	**57**	86	**57**	86
Total Operating Expenses	**80**	116	**1,143**	865
Operating Income (Loss)	**$ (229)**	$ (176)	**119**	(4)
Other (Income) Expenses				
Interest			**92**	101
Foreign exchange (gain) loss, net			**(23)**	(210)
(Gain) loss on divestitures, net			**-**	(406)
Other (gains) losses, net			**5**	(11)
Total Other (Income) Expenses			**74**	(526)
Net Earnings (Loss) Before Income Tax			**45**	522
Income tax expense (recovery)			**6**	228
Net Earnings (Loss)			**$ 39**	$ 294

(1) 2017 revenues have been realigned to conform with the January 1, 2018 adoption of ASU 2014-09 “Revenue from Contracts with Customers”.

Results of Operations (For the nine months ended September 30)

Segment and Geographic Information

	Canadian Operations		USA Operations		Market Optimization	
	2018	2017 (1)	**2018**	2017 (1)	**2018**	2017 (1)
Revenues						
Product and service revenues	**$ 1,236**	$ 801	**$ 1,880**	$ 1,336	**$ 909**	$ 614
Gains (losses) on risk management, net	**93**	6	**(185)**	30	**(3)**	-
Sublease revenues	**-**	-	**-**	-	**-**	-
Total Revenues	**1,329**	807	**1,695**	1,366	**906**	614
Operating Expenses						
Production, mineral and other taxes	**12**	16	**97**	64	**-**	-
Transportation and processing	**608**	403	**92**	141	**99**	73
Operating	**98**	89	**238**	252	**25**	23
Purchased product	**-**	-	**-**	-	**803**	565
Depreciation, depletion and amortization	**257**	170	**628**	368	**1**	1
Total Operating Expenses	**975**	678	**1,055**	825	**928**	662
Operating Income (Loss)	**$ 354**	$ 129	**$ 640**	$ 541	**$ (22)**	$ (48)

	Corporate & Other		Consolidated	
	2018	2017 (1)	**2018**	2017 (1)
Revenues				
Product and service revenues	**$ -**	$ -	**$ 4,025**	$ 2,751
Gains (losses) on risk management, net	**(422)**	396	**(517)**	432
Sublease revenues	**50**	50	**50**	50
Total Revenues	**(372)**	446	**3,558**	3,233
Operating Expenses				
Production, mineral and other taxes	**-**	-	**109**	80
Transportation and processing	**-**	-	**799**	617
Operating	**11**	13	**372**	377
Purchased product	**-**	-	**803**	565
Depreciation, depletion and amortization	**38**	51	**924**	590
Accretion of asset retirement obligation	**24**	30	**24**	30
Administrative	**187**	168	**187**	168
Total Operating Expenses	**260**	262	**3,218**	2,427
Operating Income (Loss)	**$ (632)**	$ 184	**340**	806
Other (Income) Expenses				
Interest			**265**	268
Foreign exchange (gain) loss, net			**93**	(294)
(Gain) loss on divestitures, net			**(4)**	(405)
Other (gains) losses, net			**2**	(46)
Total Other (Income) Expenses			**356**	(477)
Net Earnings (Loss) Before Income Tax			**(16)**	1,283
Income tax expense (recovery)			**(55)**	227
Net Earnings (Loss)			**$ 39**	$ 1,056

(1) 2017 revenues have been realigned to conform with the January 1, 2018 adoption of ASU 2014-09 “Revenue from Contracts with Customers”.

Intersegment Information

For the three months ended September 30,	Marketing Sales 2018	Marketing Sales 2017	Market Optimization Upstream Eliminations 2018	Market Optimization Upstream Eliminations 2017	Total 2018	Total 2017
Revenues	**$ 1,513**	$ 918	**$ (1,197)**	$ (694)	**$ 316**	$ 224
Operating Expenses						
Transportation and processing	**120**	72	**(87)**	(42)	**33**	30
Operating	**8**	11	**-**	-	**8**	11
Purchased product	**1,392**	854	**(1,110)**	(652)	**282**	202
Depreciation, depletion and amortization	**-**	1	**-**	-	**-**	1
Operating Income (Loss)	**$ (7)**	$ (20)	**$ -**	$ -	**$ (7)**	$ (20)

For the nine months ended September 30,	Marketing Sales 2018	Marketing Sales 2017	Market Optimization Upstream Eliminations 2018	Market Optimization Upstream Eliminations 2017	Total 2018	Total 2017
Revenues	**$ 4,203**	$ 2,825	**$ (3,297)**	$ (2,211)	**$ 906**	$ 614
Operating Expenses						
Transportation and processing	**335**	197	**(236)**	(124)	**99**	73
Operating	**25**	23	**-**	-	**25**	23
Purchased product	**3,864**	2,652	**(3,061)**	(2,087)	**803**	565
Depreciation, depletion and amortization	**1**	1	**-**	-	**1**	1
Operating Income (Loss)	**$ (22)**	$ (48)	**$ -**	$ -	**$ (22)**	$ (48)

Capital Expenditures

	Three Months Ended September 30, 2018	Three Months Ended September 30, 2017	Nine Months Ended September 30, 2018	Nine Months Ended September 30, 2017
Canadian Operations	**$ 174**	$ 123	**$ 553**	$ 292
USA Operations	**345**	347	**1,065**	991
Market Optimization	**-**	1	**-**	1
Corporate & Other	**4**	2	**8**	3
	$ 523	$ 473	**$ 1,626**	$ 1,287

Goodwill, Property, Plant and Equipment and Total Assets by Segment

	Goodwill As at September 30, 2018	Goodwill As at December 31, 2017	Property, Plant and Equipment As at September 30, 2018	Property, Plant and Equipment As at December 31, 2017	Total Assets As at September 30, 2018	Total Assets As at December 31, 2017
Canadian Operations	**$ 675**	$ 696	**$ 1,098**	$ 862	**$ 2,064**	$ 1,908
USA Operations	**1,913**	1,913	**6,973**	6,555	**9,744**	9,301
Market Optimization	**-**	-	**1**	2	**199**	152
Corporate & Other	**-**	-	**1,461**	1,535	**3,311**	3,906
	$ 2,588	$ 2,609	**$ 9,533**	$ 8,954	**$ 15,318**	$ 15,267

4. Revenues from Contracts with Customers

The following tables summarize the Company's revenues from contracts with customers and other sources of revenues. Encana presents realized and unrealized gains and losses on certain derivative contracts within revenues.

Revenues (For the three months ended September 30)

	Canadian Operations		USA Operations		Market Optimization	
	2018	2017	**2018**	2017	**2018**	2017
Revenues from Customers						
Product revenues [(1)]						
Oil	**$ 1**	$ 2	**$ 590**	$ 319	**$ 34**	$ 15
NGLs	**259**	107	**98**	50	**1**	-
Natural gas	**195**	126	**31**	58	**274**	199
Service revenues						
Gathering and processing	**1**	3	**4**	1	**-**	-
Product and Service Revenues	**456**	238	**723**	428	**309**	214
Other Revenues						
Gains (losses) on risk management, net [(2)]	**8**	25	**(84)**	16	**(1)**	-
Sublease revenues	**-**	-	**-**	-	**-**	-
Other Revenues	**8**	25	**(84)**	16	**(1)**	-
Total Revenues	**$ 464**	$ 263	**$ 639**	$ 444	**$ 308**	$ 214

	Corporate & Other		Consolidated	
	2018	2017	**2018**	2017
Revenues from Customers				
Product revenues [(1)]				
Oil	**$ -**	$ -	**$ 625**	$ 336
NGLs	**-**	-	**358**	157
Natural gas	**-**	-	**500**	383
Service revenues				
Gathering and processing	**-**	-	**5**	4
Product and Service Revenues	**-**	-	**1,488**	880
Other Revenues				
Gains (losses) on risk management, net [(2)]	**(164)**	(76)	**(241)**	(35)
Sublease revenues	**15**	16	**15**	16
Other Revenues	**(149)**	(60)	**(226)**	(19)
Total Revenues	**$ (149)**	$ (60)	**$ 1,262**	$ 861

(1) Includes revenues from production and revenues of product purchased from third parties, but excludes intercompany marketing fees transacted between the Company's operating segments.

(2) Canadian Operations, USA Operations and Market Optimization include realized gains/(losses) on risk management. Corporate & Other includes unrealized gains/(losses) on risk management.

Revenues (For the nine months ended September 30)

	Canadian Operations 2018	Canadian Operations 2017	USA Operations 2018	USA Operations 2017	Market Optimization 2018	Market Optimization 2017
Revenues from Customers						
Product revenues (1)						
Oil	**$ 6**	$ 5	**$ 1,579**	$ 944	**$ 84**	$ 103
NGLs	**655**	300	**221**	128	**6**	12
Natural gas	**580**	498	**92**	268	**793**	475
Service revenues						
Gathering and processing	**5**	7	**4**	11	**-**	-
Product and Service Revenues	**1,246**	810	**1,896**	1,351	**883**	590
Other Revenues						
Gains (losses) on risk management, net (2)	**93**	6	**(185)**	30	**(3)**	-
Sublease revenues	**-**	-	**-**	-	**-**	-
Other Revenues	**93**	6	**(185)**	30	**(3)**	-
Total Revenues	**$ 1,339**	$ 816	**$ 1,711**	$ 1,381	**$ 880**	$ 590

	Corporate & Other 2018	Corporate & Other 2017	Consolidated 2018	Consolidated 2017
Revenues from Customers				
Product revenues (1)				
Oil	**$ -**	$ -	**$ 1,669**	$ 1,052
NGLs	**-**	-	**882**	440
Natural gas	**-**	-	**1,465**	1,241
Service revenues				
Gathering and processing	**-**	-	**9**	18
Product and Service Revenues	**-**	-	**4,025**	2,751
Other Revenues				
Gains (losses) on risk management, net (2)	**(422)**	396	**(517)**	432
Sublease revenues	**50**	50	**50**	50
Other Revenues	**(372)**	446	**(467)**	482
Total Revenues	**$ (372)**	$ 446	**$ 3,558**	$ 3,233

(1) Includes revenues from production and revenues of product purchased from third parties, but excludes intercompany marketing fees transacted between the Company's operating segments.
(2) Canadian Operations, USA Operations and Market Optimization include realized gains/(losses) on risk management. Corporate & Other includes unrealized gains/(losses) on risk management.

The Company's revenues from contracts with customers consists of product sales including oil, NGLs and natural gas, as well as the provision of gathering and processing services to third parties. Encana had no contract asset or liability balances during the periods presented. As at September 30, 2018, receivables and accrued revenues from contracts with customers were $764 million ($676 million as at December 31, 2017).

Performance obligations arising from product sales contracts are typically satisfied at a point in time when the product is delivered to the customer and control is transferred. Payment from the customer is due when the product is delivered to the custody point. The Company's product sales are sold under short-term contracts with terms that are less than one year at either fixed or market index prices or under long-term contracts exceeding one year at market index prices.

As at September 30, 2018, all remaining performance obligations are priced at market index prices or are variable volume delivery contracts. As such, the variable consideration is allocated entirely to the wholly unsatisfied performance obligation or promise to deliver units of production, and revenue is recognized at the amount for which the Company has the right to invoice the product delivered.

Performance obligations arising from arrangements to gather and process natural gas on behalf of third parties are typically satisfied over time as the service is provided to the customer. Payment from the customer is due when the customer receives the benefit of the service and the product is delivered to the custody point or plant tailgate. The Company's gathering and processing services are provided on an interruptible basis with transaction prices that are for fixed prices and/or variable consideration. Variable consideration received is related to recovery of plant operating costs or escalation of the fixed price based on a consumer price index. As the service contracts are interruptible, with service provided on an "as available" basis, there are no unsatisfied performance obligations remaining at September 30, 2018.

5. Interest

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2018	2017	**2018**	2017
Interest Expense on:				
Debt	**$ 67**	$ 67	**$ 200**	$ 200
The Bow office building	**16**	16	**48**	47
Capital leases	**3**	6	**12**	16
Other	**6**	12	**5**	5
	$ 92	$ 101	**$ 265**	$ 268

6. Foreign Exchange (Gain) Loss, Net

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2018	2017	**2018**	2017
Unrealized Foreign Exchange (Gain) Loss on:				
Translation of U.S. dollar financing debt issued from Canada	**$ (74)**	$ (187)	**$ 138**	$ (265)
Translation of U.S. dollar risk management contracts issued from Canada	**(3)**	(21)	**7**	(53)
Translation of intercompany notes	**54**	(10)	**11**	1
	(23)	(218)	**156**	(317)
Foreign Exchange on Settlements of:				
U.S. dollar financing debt issued from Canada	**-**	3	**1**	10
U.S. dollar risk management contracts issued from Canada	**(1)**	(9)	**(11)**	(8)
Intercompany notes	**(1)**	15	**(48)**	17
Other Monetary Revaluations	**2**	(1)	**(5)**	4
	$ (23)	$ (210)	**$ 93**	$ (294)

The unrealized foreign exchange (gain) loss on translation of U.S. dollar financing debt issued from Canada for the nine months ended September 30, 2017 disclosed in the table above included an out-of-period adjustment in respect of unrealized losses on a foreign-denominated capital lease obligation since December 2013. The cumulative impact recognized within foreign exchange (gain) loss in the Company's Condensed Consolidated Statement of Earnings for the nine months ended September 30, 2017 was $68 million, before tax ($47 million, after tax). Encana determined that the adjustment was not material to the Condensed Consolidated Financial Statements for the period ended September 30, 2017 or any prior periods.

7. Income Taxes

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2018	2017	**2018**	2017
Current Tax				
Canada	**$ -**	$ -	**$ (66)**	$ (62)
United States	**-**	1	**2**	2
Other Countries	**-**	-	**3**	4
Total Current Tax Expense (Recovery)	**-**	1	**(61)**	(56)
Deferred Tax				
Canada	**19**	71	**(9)**	91
United States	**(3)**	101	**4**	122
Other Countries	**(10)**	55	**11**	70
Total Deferred Tax Expense (Recovery)	**6**	227	**6**	283
Income Tax Expense (Recovery)	**$ 6**	$ 228	**$ (55)**	$ 227
Effective Tax Rate	**13.3%**	43.7%	**343.8%**	17.7%

Encana's interim income tax expense is determined using the 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, 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.

During the nine months ended September 30, 2018, the current income tax recovery was primarily due to the resolution of certain tax items relating to prior taxation years. During the nine months ended September 30, 2017, the current income tax recovery was primarily due to the successful resolution of certain tax items previously assessed by the taxing authorities relating to prior taxation years. During the three months ended September 30, 2018, the deferred tax expense was primarily due to the changes in the estimated annual effective income tax rate. During the three months ended September 30, 2017, the deferred tax expense was primarily due to the changes in the estimated annual effective income tax rate arising from gains recognized on foreign exchange and divestitures, including allocated goodwill.

The effective tax rate of 343.8 percent for the nine months ended September 30, 2018 is higher than the Canadian statutory rate of 27 percent primarily due to the current year items discussed above. The effective tax rate of 17.7 percent for the nine months ended September 30, 2017 is lower than the Canadian statutory rate of 27 percent primarily due to the items discussed above.

During the nine months ended September 30, 2018, there was no change to the provisional tax adjustment recognized in 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. The provisional amount recognized may change due to additional regulatory guidance that may be issued, and from additional analysis or changes in interpretation and assumptions of the U.S. Tax Reform made by the Company.

8. Acquisitions and Divestitures

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2018	2017	**2018**	2017
Acquisitions				
Canadian Operations	**$ 15**	$ -	**$ 17**	$ 31
USA Operations	**-**	2	**-**	19
Total Acquisitions	**15**	2	**17**	50
Divestitures				
Canadian Operations	**2**	(20)	**(55)**	(26)
USA Operations	**(26)**	(605)	**(34)**	(684)
Total Divestitures	**(24)**	(625)	**(89)**	(710)
Net Acquisitions & (Divestitures)	**$ (9)**	$ (623)	**$ (72)**	$ (660)

Acquisitions

For the nine months ended September 30, 2018, acquisitions in the Canadian and USA Operations were $17 million (2017 - $31 million) and nil (2017 - $19 million), respectively, which primarily included purchases with oil and liquids rich potential.

Divestitures

In the Canadian Operations, divestitures during the nine months ended September 30, 2018 were $55 million, which primarily included the sale of the Pipestone midstream assets located in Alberta. During the nine months ended September 30, 2017, divestitures in the Canadian Operations were $26 million, which primarily included the sale of certain properties that did not complement Encana's existing portfolio of assets.

In the USA Operations, divestitures during the three and nine months ended September 30, 2018 were $26 million and $34 million, respectively, which primarily included the sale of certain properties that did not complement Encana's existing portfolio of assets. During the three months ended September 30, 2017, divestitures in the USA Operations comprised the sale of the Piceance natural gas assets in northwestern Colorado for proceeds of approximately $605 million, after closing and other adjustments. During the nine months ended September 30, 2017, divestitures in the USA Operations were $684 million, which primarily included the sale of the Piceance natural gas assets and the sale of the Tuscaloosa Marine Shale assets in Mississippi and Louisiana.

Amounts received from the Company's divestiture transactions have been 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. For divestitures that result in a gain or loss and constitute a business, goodwill is allocated to the divestiture. Accordingly, for the three and nine months ended September 30, 2017, Encana recognized a gain of approximately $406 million, before tax, on the sale of the Company's Piceance assets in the U.S. cost centre and allocated goodwill of $216 million.

9. Property, Plant and Equipment, Net

	As at September 30, 2018			As at December 31, 2017		
	Cost	**Accumulated DD&A**	**Net**	Cost	Accumulated DD&A	Net
Canadian Operations						
Proved properties	**$ 14,685**	**$ (13,869)**	**$ 816**	$ 14,555	$ (14,047)	$ 508
Unproved properties	**255**	**-**	**255**	311	-	311
Other	**27**	**-**	**27**	43	-	43
	14,967	**(13,869)**	**1,098**	14,909	(14,047)	862
USA Operations						
Proved properties	**27,116**	**(23,869)**	**3,247**	25,610	(23,240)	2,370
Unproved properties	**3,709**	**-**	**3,709**	4,169	-	4,169
Other	**17**	**-**	**17**	16	-	16
	30,842	**(23,869)**	**6,973**	29,795	(23,240)	6,555
Market Optimization	**7**	**(6)**	**1**	7	(5)	2
Corporate & Other	**2,236**	**(775)**	**1,461**	2,299	(764)	1,535
	$ 48,052	**$ (38,519)**	**$ 9,533**	$ 47,010	$ (38,056)	$ 8,954

Canadian and USA Operations property, plant and equipment include internal costs directly related to exploration, development and construction activities of $159 million, which have been capitalized during the nine months ended September 30, 2018 (2017 - $146 million). Included in Corporate and Other are $58 million ($63 million as at December 31, 2017) of international property costs, which have been fully impaired.

Capital Lease Arrangements

The Company has several lease arrangements that are accounted for as capital leases including an office building and an offshore production platform.

As at September 30, 2018, the total carrying value of assets under capital lease was $43 million ($46 million as at December 31, 2017), net of accumulated amortization of $673 million ($684 million as at December 31, 2017). Liabilities for the capital lease arrangements are included in other liabilities and provisions in the Condensed Consolidated Balance Sheet and are disclosed in Note 11.

Other Arrangement

As at September 30, 2018, Corporate and Other property, plant and equipment and total assets include a carrying value of $1,200 million ($1,255 million as at December 31, 2017) related to The Bow office building, which is under a 25-year lease agreement. The Bow asset is being depreciated over the 60-year estimated life of the building. At the conclusion of the 25-year term, the remaining asset and corresponding liability are expected to be derecognized as disclosed in Note 11.

10. Long-Term Debt

		As at September 30, 2018		As at December 31, 2017
U.S. Dollar Denominated Debt				
U.S. Unsecured Notes:				
6.50% due May 15, 2019	$	500	$	500
3.90% due November 15, 2021		600		600
8.125% due September 15, 2030		300		300
7.20% due November 1, 2031		350		350
7.375% due November 1, 2031		500		500
6.50% due August 15, 2034		750		750
6.625% due August 15, 2037		462		462
6.50% due February 1, 2038		505		505
5.15% due November 15, 2041		244		244
Total Principal		4,211		4,211
Increase in Value of Debt Acquired		24		26
Unamortized Debt Discounts and Issuance Costs		(37)		(40)
Current Portion of Long-Term Debt		(500)		-
	$	3,698	$	4,197

As at September 30, 2018, total long-term debt had a carrying value of $4,198 million and a fair value of $4,766 million (as at December 31, 2017 - carrying value of $4,197 million and a fair value of $5,042 million). The estimated fair value of long-term borrowings is categorized within Level 2 of the fair value hierarchy and has been determined based on market information of long-term debt with similar terms and maturity, or by discounting future payments of interest and principal at interest rates expected to be available to the Company at period end.

11. Other Liabilities and Provisions

		As at September 30, 2018		As at December 31, 2017
The Bow Office Building	$	1,293	$	1,344
Capital Lease Obligations		233		295
Unrecognized Tax Benefits		172		202
Pensions and Other Post-Employment Benefits		121		116
Long-Term Incentive Costs (See Note 16)		67		175
Other Derivative Contracts (See Notes 18, 19)		10		14
Other		20		21
	$	1,916	$	2,167

The Bow Office Building

As described in Note 9, Encana has recognized the accumulated costs for The Bow office building, which is under a 25-year lease agreement. At the conclusion of the lease term, the remaining asset and corresponding liability are expected to be derecognized. Encana has also subleased approximately 50 percent of The Bow office space under the lease agreement. The total expected future principal and interest payments related to the 25-year lease agreement and the total undiscounted future amounts expected to be recovered from the sublease are outlined below.

	2018	2019	2020	2021	2022	Thereafter	Total
Expected Future Lease Payments	$ 18	$ 74	$ 75	$ 76	$ 76	$ 1,255	**$ 1,574**
Less: Amounts Representing Interest	16	62	62	61	60	777	**1,038**
Present Value of Expected Future Lease Payments	$ 2	$ 12	$ 13	$ 15	$ 16	$ 478	**$ 536**
Sublease Recoveries (undiscounted)	$ (9)	$ (37)	$ (37)	$ (37)	$ (37)	$ (617)	**$ (774)**

Capital Lease Obligations

As described in Note 9, the Company has several lease arrangements that are accounted for as capital leases including an office building and the Deep Panuke offshore Production Field Centre ("PFC"). Variable interests related to the PFC are described in Note 15.

The total expected future lease payments related to the Company's capital lease obligations are outlined below.

	2018	2019	2020	2021	2022	Thereafter	Total
Expected Future Lease Payments	$ 25	$ 99	$ 99	$ 87	$ 8	$ 38	**$ 356**
Less: Amounts Representing Interest	5	15	10	4	2	5	**41**
Present Value of Expected Future Lease Payments	$ 20	$ 84	$ 89	$ 83	$ 6	$ 33	**$ 315**

12. Asset Retirement Obligation

	As at September 30, 2018	As at December 31, 2017
Asset Retirement Obligation, Beginning of Year	**$ 514**	$ 687
Liabilities Incurred and Acquired	**13**	11
Liabilities Settled and Divested	**(28)**	(333)
Change in Estimated Future Cash Outflows	**-**	88
Accretion Expense	**24**	37
Foreign Currency Translation	**(12)**	24
Asset Retirement Obligation, End of Period	**$ 511**	$ 514
Current Portion	**$ 104**	$ 44
Long-Term Portion	**407**	470
	$ 511	$ 514

13. Share Capital

Authorized

The Company is authorized to issue an unlimited number of no par value common shares and Class A Preferred Shares limited to a number equal to not more than 20 percent of the issued and outstanding number of common shares at the time of issuance. No Class A Preferred Shares are outstanding.

Issued and Outstanding

	As at September 30, 2018			As at December 31, 2017		
	Number (millions)		Amount	Number (millions)		Amount
Common Shares Outstanding, Beginning of Year	973.1	$	4,757	973.0	$	4,756
Common Shares Purchased	(20.7)		(102)	-		-
Common Shares Issued Under Dividend Reinvestment Plan	-		-	0.1		1
Common Shares Outstanding, End of Period	952.4	$	4,655	973.1	$	4,757

During the nine months ended September 30, 2018, Encana issued 40,057 common shares totaling $0.5 million under the Company's dividend reinvestment plan ("DRIP"). During the twelve months ended December 31, 2017, Encana issued 58,480 common shares totaling $0.6 million under the DRIP.

Dividends

During the three months ended September 30, 2018, Encana paid dividends of $0.015 per common share totaling $14 million (2017 - $0.015 per common share totaling $15 million). During the nine months ended September 30, 2018, Encana paid dividends of $0.045 per common share totaling $43 million (2017 - $0.045 per common share totaling $44 million).

For the three and nine months ended September 30, 2018, the dividends paid included $0.1 million and $0.5 million, respectively, in common shares issued in lieu of cash dividends under the DRIP (for the three and nine months ended September 30, 2017 - $0.2 million and $0.5 million, respectively).

On October 31, 2018, the Board of Directors declared a dividend of $0.015 per common share payable on December 31, 2018 to common shareholders of record as of December 14, 2018.

Normal Course Issuer Bid

On February 26, 2018, the Company announced it received approval from the TSX to purchase, for cancellation, up to 35 million common shares pursuant to a NCIB over a 12-month period from February 28, 2018 to February 27, 2019. The Company has authorization from its Board to spend up to $400 million on the NCIB.

All purchases are made in accordance with the NCIB at prevailing market prices plus brokerage fees, with consideration allocated to share capital up to the average carrying amount of the shares, and any excess is allocated to retained earnings/accumulated deficit.

For the nine months ended September 30, 2018, the Company purchased approximately 20.7 million common shares for total consideration of approximately $250 million. Of the amount paid, $102 million was charged to share capital and $148 million was charged to accumulated deficit.

Earnings Per Common Share

The following table presents the computation of net earnings (loss) per common share:

(US$ millions, except per share amounts)	Three Months Ended September 30,				Nine Months Ended September 30,			
		2018		2017		**2018**		2017
Net Earnings (Loss)	**$**	**39**	$	294	**$**	**39**	$	1,056
Number of Common Shares:								
Weighted average common shares outstanding - Basic		**955.1**		973.1		**962.2**		973.1
Effect of dilutive securities		**-**		-		**-**		-
Weighted Average Common Shares Outstanding - Diluted		**955.1**		973.1		**962.2**		973.1
Net Earnings (Loss) per Common Share								
Basic & Diluted	**$**	**0.04**	$	0.30	**$**	**0.04**	$	1.09

Encana Stock Option Plan

Encana has share-based compensation plans that allow employees to purchase common shares of the Company. Option exercise prices are not less than the market value of the common shares on the date the options are granted. All options outstanding as at September 30, 2018 have associated Tandem Stock Appreciation Rights ("TSARs") attached. In lieu of exercising the option, the associated TSARs give the option holder the right to receive a cash payment equal to the excess of the market price of Encana's common shares at the time of the exercise over the original grant price.

In addition, certain stock options granted are performance-based whereby vesting is also subject to Encana attaining prescribed performance relative to predetermined key measures. Historically, most holders of options with TSARs have elected to exercise their stock options as a Stock Appreciation Right ("SAR") in exchange for a cash payment. As a result, outstanding TSARs are not considered potentially dilutive securities.

Encana Restricted Share Units ("RSUs")

Encana has a share-based compensation plan whereby eligible employees and Directors are granted RSUs. An RSU is a conditional grant to receive the equivalent of an Encana common share upon vesting of the RSUs and in accordance with the terms of the RSU Plan and Grant Agreement. The Company currently settles vested RSUs in cash. As a result, RSUs are not considered potentially dilutive securities.

14. Accumulated Other Comprehensive Income

	Three Months Ended September 30,				Nine Months Ended September 30,			
		2018		2017		**2018**		2017
Foreign Currency Translation Adjustment								
Balance, Beginning of Period	**$**	**1,028**	$	1,125	**$**	**1,029**	$	1,200
Change in Foreign Currency Translation Adjustment		**22**		(97)		**21**		(172)
Balance, End of Period	**$**	**1,050**	$	1,028	**$**	**1,050**	$	1,028
Pension and Other Post-Employment Benefit Plans								
Balance, Beginning of Period	**$**	**12**	$	9	**$**	**13**	$	10
Reclassification of Net Actuarial (Gains) and Losses to Net Earnings (See Note 17)		**-**		-		**(1)**		(1)
Income Taxes		**-**		-		**-**		-
Curtailment in Net Defined Periodic Benefit Cost (See Note 17)		**-**		(1)		**-**		(1)
Income Taxes		**-**		-		**-**		-
Balance, End of Period	**$**	**12**	$	8	**$**	**12**	$	8
Total Accumulated Other Comprehensive Income	**$**	**1,062**	$	1,036	**$**	**1,062**	$	1,036

15. Variable Interest Entities

Production Field Centre

In 2008, Encana entered into a contract for the design, construction and operation of the PFC at its Deep Panuke facility. Upon commencement of operations in December 2013, Encana recognized the PFC as a capital lease asset. Under the lease contract, Encana has a purchase option and the option to extend the lease for 12 one-year terms at fixed prices after the initial lease term expires in 2021.

As a result of the purchase option and fixed price renewal options, Encana has determined it holds variable interests and that the related leasing entity qualifies as a variable interest entity ("VIE"). Encana is not the primary beneficiary of the VIE as the Company does not have the power to direct the activities that most significantly impact the VIE's economic performance. Encana is not required to provide any financial support or guarantees to the leasing entity or its affiliates, other than the contractual payments under the lease and operating agreements. Encana's maximum exposure is the expected lease payments over the initial contract term. As at September 30, 2018, Encana had a capital lease obligation of $259 million ($314 million as at December 31, 2017) related to the PFC.

Veresen Midstream Limited Partnership

Veresen Midstream Limited Partnership ("VMLP") provides gathering, compression and processing services under various agreements related to the Company's development of liquids and natural gas production in the Montney play. As at September 30, 2018, VMLP provides approximately 1,240 MMcf/d of natural gas gathering and compression and 977 MMcf/d of natural gas processing under long-term service agreements with remaining terms ranging from up to 13 to 27 years and have various renewal terms providing up to a potential maximum of 10 years.

Encana has determined that VMLP is a VIE and that Encana holds variable interests in VMLP. Encana is not the primary beneficiary as the Company does not have the power to direct the activities that most significantly impact VMLP's economic performance. These key activities relate to the construction, operation, maintenance and marketing of the assets owned by VMLP. The variable interests arise from certain terms under the various long-term service agreements and include: i) a take or pay for volumes in certain agreements; ii) an operating fee of which a portion can be converted into a fixed fee once VMLP assumes operatorship of certain assets; and iii) a potential payout of minimum costs in certain agreements. The potential payout of minimum costs will be assessed in the eighth year of the assets' service period and is based on whether there is an overall shortfall of total system cash flows from natural gas gathered and compressed under certain agreements. The potential payout amount can be reduced in the event VMLP markets unutilized capacity to third party users. Encana is not required to provide any financial support or guarantees to VMLP.

As a result of Encana's involvement with VMLP, the maximum total exposure, which represents the potential exposure to Encana in the event the assets under the agreements are deemed worthless, is estimated to be $2,425 million as at September 30, 2018. The estimate comprises the take or pay volume commitments and the potential payout of minimum costs. The take or pay volume commitments associated with certain gathering and processing assets are included in Note 21 under Transportation and Processing. The potential payout requirement is highly uncertain as the amount is contingent on future production estimates, pace of development and the amount of capacity contracted to third parties. As at September 30, 2018, there were no accounts payable and accrued liabilities outstanding related to the take or pay commitment.

16. Compensation Plans

Encana has a number of compensation arrangements under which the Company awards various types of long-term incentive grants to eligible employees and Directors. They may include TSARs, Performance TSARs, SARs, Performance Share Units ("PSUs"), Deferred Share Units ("DSUs") and RSUs. These compensation arrangements are share-based.

Encana accounts for TSARs, Performance TSARs, SARs, PSUs and RSUs as cash-settled share-based payment transactions and, accordingly, accrues compensation costs over the vesting period based on the fair value of the rights determined using the Black-Scholes-Merton and other fair value models.

The following weighted average assumptions were used to determine the fair value of the share units outstanding:

	As at September 30, 2018		As at September 30, 2017	
	US$ Share Units	**C$ Share Units**	US$ Share Units	C$ Share Units
Risk Free Interest Rate	**2.18%**	**2.18%**	1.53%	1.53%
Dividend Yield	**0.46%**	**0.46%**	0.51%	0.53%
Expected Volatility Rate (1)	**55.44%**	**51.90%**	59.35%	55.21%
Expected Term	**1.6 yrs**	**2.0 yrs**	1.6 yrs	1.7 yrs
Market Share Price	**US$13.11**	**C$16.93**	US$11.78	C$14.69

(1) Volatility was estimated using historical rates.

The Company has recognized the following share-based compensation costs:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2018	2017	**2018**	2017
Total Compensation Costs of Transactions Classified as Cash-Settled	**$ 36**	$ 91	**$ 118**	$ 84
Less: Total Share-Based Compensation Costs Capitalized	**(11)**	(30)	**(33)**	(30)
Total Share-Based Compensation Expense (Recovery)	**$ 25**	$ 61	**$ 85**	$ 54
Recognized on the Condensed Consolidated Statement of Earnings in:				
Operating	**$ 8**	$ 18	**$ 24**	$ 18
Administrative	**17**	43	**61**	36
	$ 25	$ 61	**$ 85**	$ 54

As at September 30, 2018, the liability for share-based payment transactions totaled $357 million ($327 million as at December 31, 2017), of which $290 million ($152 million as at December 31, 2017) is recognized in accounts payable and accrued liabilities and $67 million ($175 million as at December 31, 2017) is recognized in other liabilities and provisions in the Condensed Consolidated Balance Sheet.

	As at September 30, 2018	As at December 31, 2017
Liability for Cash-Settled Share-Based Payment Transactions:		
Unvested	**$ 287**	$ 274
Vested	**70**	53
	$ 357	$ 327

The following units were granted primarily in conjunction with the Company's February annual long-term incentive award. The TSARs, SARs, PSUs and RSUs were granted at the volume-weighted average trading price of Encana's common shares for the five days prior to the grant date.

Nine Months Ended September 30, 2018 (thousands of units)	
TSARs	872
SARs	377
PSUs	2,546
DSUs	45
RSUs	5,358

17. Pension and Other Post-Employment Benefits

The Company has recognized total benefit plans expense which includes pension benefits and other post-employment benefits ("OPEB") for the nine months ended September 30 as follows:

	Pension Benefits		OPEB		Total	
	2018	2017	**2018**	2017	**2018**	2017
Net Defined Periodic Benefit Cost	**$ 1**	$ -	**$ 5**	$ 1	**$ 6**	$ 1
Defined Contribution Plan Expense	**17**	17	**-**	-	**17**	17
Total Benefit Plans Expense	**$ 18**	$ 17	**$ 5**	$ 1	**$ 23**	$ 18

Of the total benefit plans expense, $17 million (2017 - $18 million) was included in operating expense, $6 million (2017 - $6 million) was included in administrative expense and a gain of nil (2017 - $6 million) was included in other (gains) losses, net.

The net defined periodic benefit cost for the nine months ended September 30 is as follows:

	Defined Benefits		OPEB		Total	
	2018	2017	**2018**	2017	**2018**	2017
Service Cost	**$ 1**	$ 1	**$ 5**	$ 6	**$ 6**	$ 7
Interest Cost	**5**	6	**2**	2	**7**	8
Expected Return on Plan Assets	**(6)**	(7)	**-**	-	**(6)**	(7)
Amounts Reclassified from Accumulated Other Comprehensive Income:						
Amortization of net actuarial (gains) and losses	**1**	-	**(2)**	(1)	**(1)**	(1)
Curtailment	**-**	-	**-**	(1)	**-**	(1)
Curtailment	**-**	-	**-**	(5)	**-**	(5)
Total Net Defined Periodic Benefit Cost (1)	**$ 1**	$ -	**$ 5**	$ 1	**$ 6**	$ 1

(1) The components of total net defined periodic benefit cost, excluding the service cost component, are included in other (gains) losses, net.

18. Fair Value Measurements

The fair values of cash and cash equivalents, accounts receivable and accrued revenues, and accounts payable and accrued liabilities approximate their carrying amounts due to the short-term maturity of those instruments.

Recurring fair value measurements are performed for risk management assets and liabilities and other derivative contracts, as discussed further in Note 19. These items are carried at fair value in the Condensed Consolidated Balance Sheet and are classified within the three levels of the fair value hierarchy in the following tables. There have been no significant transfers between the hierarchy levels during the period.

Fair value changes and settlements for amounts related to risk management assets and liabilities are recognized in revenues, transportation and processing expense, and foreign exchange gains and losses according to their purpose.

As at September 30, 2018	Level 1 Quoted Prices in Active Markets	Level 2 Other Observable Inputs	Level 3 Significant Unobservable Inputs	Total Fair Value	Netting (1)	Carrying Amount
Risk Management Assets						
Commodity Derivatives:						
Current assets	**$ 13**	**$ 200**	**$ -**	**$ 213**	**$ (77)**	**$ 136**
Long-term assets	**-**	**144**	**-**	**144**	**(14)**	**130**
Foreign Currency Derivatives:						
Current assets	**-**	**10**	**-**	**10**	**-**	**10**
Long-term assets	**-**	**2**	**-**	**2**	**-**	**2**
Risk Management Liabilities						
Commodity Derivatives:						
Current liabilities	**$ -**	**$ 405**	**$ 122**	**$ 527**	**$ (77)**	**$ 450**
Long-term liabilities	**-**	**56**	**26**	**82**	**(14)**	**68**
Foreign Currency Derivatives:						
Current liabilities	**-**	**-**	**-**	**-**	**-**	**-**
Other Derivative Contracts						
Current in accounts payable and accrued liabilities	**$ -**	**$ 5**	**$ -**	**$ 5**	**$ -**	**$ 5**
Long-term in other liabilities and provisions	**-**	**10**	**-**	**10**	**-**	**10**

As at December 31, 2017	Level 1 Quoted Prices in Active Markets	Level 2 Other Observable Inputs	Level 3 Significant Unobservable Inputs	Total Fair Value	Netting (1)	Carrying Amount
Risk Management Assets						
Commodity Derivatives:						
Current assets	$ -	$ 189	$ -	$ 189	$ (15)	$ 174
Long-term assets	-	248	-	248	(2)	246
Foreign Currency Derivatives:						
Current assets	-	31	-	31	-	31
Risk Management Liabilities						
Commodity Derivatives:						
Current liabilities	$ 3	$ 196	$ 51	$ 250	$ (15)	$ 235
Long-term liabilities	-	15	-	15	(2)	13
Foreign Currency Derivatives:						
Current liabilities	-	1	-	1	-	1
Other Derivative Contracts						
Current in accounts payable and accrued liabilities	$ -	$ 5	$ -	$ 5	$ -	$ 5
Long-term in other liabilities and provisions	-	14	-	14	-	14

(1) Netting to offset derivative assets and liabilities where the legal right and intention to offset exists, or where counterparty master netting arrangements contain provisions for net settlement.

The Company's Level 1 and Level 2 risk management assets and liabilities consist of commodity fixed price contracts, fixed price swaptions, NYMEX call options, foreign currency swaps and basis swaps with terms to 2023. Level 2 also includes financial guarantee contracts as discussed in Note 19. The fair values of these contracts are based on a market approach and are estimated using inputs which are either directly or indirectly observable at the reporting date, such as exchange and other published prices, broker quotes and observable trading activity.

Level 3 Fair Value Measurements

As at September 30, 2018, the Company's Level 3 risk management assets and liabilities consist of WTI three-way options and WTI costless collars with terms to 2019. The WTI three-way options are a combination of a sold call, bought put and a sold put. The WTI costless collars are a combination of a sold call and a bought put. These contracts allow the Company to participate in the upside of commodity prices to the ceiling of the call option and provide the Company with complete (collars) or partial (three-way) downside price protection through the put options. The fair values of the WTI three-way options and WTI costless collars are based on the income approach and are modelled using observable and unobservable inputs such as implied volatility. The unobservable inputs are obtained from third parties whenever possible and reviewed by the Company for reasonableness.

A summary of changes in Level 3 fair value measurements for the nine months ended September 30 is presented below:

	Risk Management			
		2018		2017
Balance, Beginning of Year	**$**	**(51)**	$	(36)
Total Gains (Losses)		**(177)**		38
Purchases, Sales, Issuances and Settlements:				
Purchases, sales and issuances		**-**		-
Settlements		**80**		(9)
Transfers Out of Level 3 (1)		**-**		-
Balance, End of Period	**$**	**(148)**	$	(7)
Change in Unrealized Gains (Losses) Related to Assets and Liabilities Held at End of Period	**$**	**(136)**	$	8

(1) The Company's policy is to recognize transfers out of Level 3 on the date of the event of change in circumstances that caused the transfer.

Quantitative information about unobservable inputs used in Level 3 fair value measurements is presented below:

	Valuation Technique	Unobservable Input	**As at September 30, 2018**	As at December 31, 2017
Risk Management - WTI Options	Option Model	Implied Volatility	**23% - 102%**	17% - 76%

A 10 percent increase or decrease in implied volatility for the WTI options would cause a corresponding $7 million ($2 million as at December 31, 2017) increase or decrease to net risk management assets and liabilities.

19. Financial Instruments and Risk Management

A) Financial Instruments

Encana's financial assets and liabilities are recognized in cash and cash equivalents, accounts receivable and accrued revenues, accounts payable and accrued liabilities, risk management assets and liabilities, long-term debt and other liabilities and provisions.

B) Risk Management Activities

Encana uses derivative financial instruments to manage its exposure to cash flow variability from commodity prices and fluctuating foreign currency exchange rates. The Company does not apply hedge accounting to any of its derivative financial instruments. As a result, gains and losses from changes in the fair value are recognized in net earnings.

Commodity Price Risk

Commodity price risk arises from the effect that fluctuations in future commodity prices may have on future cash flows. To partially mitigate exposure to commodity price risk, the Company has entered into various derivative financial instruments. The use of these derivative instruments is governed under formal policies and is subject to limits established by the Board of Directors. The Company's policy is to not use derivative financial instruments for speculative purposes.

Crude Oil and NGLs - To partially mitigate crude oil and NGL commodity price risk, the Company uses WTI-based and Mont Belvieu-based contracts such as fixed price contracts, fixed price swaptions, options and costless collars. Encana has also entered into basis swaps to manage against widening price differentials between various production areas and benchmark price points.

Natural Gas - To partially mitigate natural gas commodity price risk, the Company uses NYMEX-based contracts such as fixed price contracts, fixed price swaptions and options. Encana has also entered into basis swaps to manage against widening price differentials between various production areas and benchmark price points.

Foreign Exchange Risk

Foreign exchange risk arises from changes in foreign currency exchange rates that may affect the fair value or future cash flows of the Company's financial assets or liabilities. To partially mitigate the effect of foreign exchange fluctuations on future commodity revenues and expenses, the Company may enter into foreign currency derivative contracts. As at September 30, 2018, Encana has entered into $179 million notional U.S. dollar denominated currency swaps at an average exchange rate of US$0.7606 to C$1, which mature monthly through the remainder of 2018 and $350 million notional U.S. dollar denominated currency swaps at an average exchange rate of US$0.7579 to C$1, which mature monthly throughout 2019.

Risk Management Positions as at September 30, 2018

	Notional Volumes	Term	Average Price	Fair Value
Crude Oil and NGL Contracts			**US$/bbl**	
Fixed Price Contracts				
WTI Fixed Price	110.5 Mbbls/d	2018	55.65	$ **(175)**
WTI Fixed Price	35.0 Mbbls/d	2019	60.31	**(134)**
Propane Fixed Price	9.0 Mbbls/d	2018	39.05	**(5)**
Propane Fixed Price	4.8 Mbbls/d	2019	34.87	**(9)**
Butane Fixed Price	7.0 Mbbls/d	2018	43.49	**(7)**
Butane Fixed Price	3.0 Mbbls/d	2019	38.89	**(8)**
Ethane Fixed Price	3.0 Mbbls/d	2019	17.19	**(1)**
WTI Fixed Price Swaptions (1)	24.0 Mbbls/d	Q1 - Q2 2019	63.13	**(42)**
WTI Three-Way Options				
Sold call / bought put / sold put	16.0 Mbbls/d	2018	54.49 / 47.17 / 36.88	**(25)**
Sold call / bought put / sold put	52.5 Mbbls/d	2019	69.22 / 59.47 / 48.57	**(110)**
WTI Costless Collars				
Sold call / bought put	10.0 Mbbls/d	2018	57.08 / 45.00	**(13)**
Basis Contracts (2)		2018		**15**
		2019		**27**
		2020		**(4)**
Crude Oil and NGLs Fair Value Position				**(491)**
Natural Gas Contracts			**US$/Mcf**	
Fixed Price Contracts				
NYMEX Fixed Price	1,017 MMcf/d	2018	3.03	**(1)**
NYMEX Fixed Price	742 MMcf/d	2019	2.73	**(13)**
NYMEX Fixed Price Swaptions (3)	300 MMcf/d	Q1 - Q2 2019	2.99	**(7)**
NYMEX Call Options				
Sold call price	230 MMcf/d	2018	3.75	**-**
Sold call price	230 MMcf/d	2019	3.75	**(4)**
Bought call price	230 MMcf/d	2019	3.75	**-**
Sold call price	230 MMcf/d	2020	3.25	**1**
Basis Contracts (4)		2018		**35**
		2019		**126**
		2020		**88**
		2021 - 2023		**18**
Natural Gas Fair Value Position				**243**
Net Premiums Received on Unexpired Options				**(4)**
Other Derivative Contracts				
Fair Value Position				**(15)**
Foreign Currency Contracts				
Fair Value Position (5)		2018 - 2019		**12**
Total Fair Value Position and Net Premiums Received				$ **(255)**

(1) WTI Fixed Price Swaptions give the counterparty the option to extend certain Q3 - Q4 2018 Fixed Price swaps to Q1- Q2 2019.
(2) Encana has entered into swaps to protect against weakening Midland, Magellan East Houston, Louisiana Light Sweet and Edmonton Condensate differentials to WTI.
(3) NYMEX Fixed Price Swaptions give the counterparty the option to extend certain Q3 - Q4 2018 Fixed Price swaps to Q1- Q2 2019.
(4) Encana has entered into swaps to protect against weakening AECO, Dawn, Chicago, Malin and Waha basis to NYMEX.
(5) Encana has entered into U.S. dollar denominated fixed-for-floating average currency swaps to protect against fluctuations between the Canadian and U.S. dollars.

Earnings Impact of Realized and Unrealized Gains (Losses) on Risk Management Positions

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2018	2017	**2018**	2017
Realized Gains (Losses) on Risk Management				
Commodity and Other Derivatives:				
Revenues [(1)]	**$ (77)**	$ 41	**$ (95)**	$ 36
Transportation and processing	**-**	-	**-**	(4)
Foreign Currency Derivatives:				
Foreign exchange	**1**	9	**11**	8
	$ (76)	$ 50	**$ (84)**	$ 40
Unrealized Gains (Losses) on Risk Management				
Commodity and Other Derivatives:				
Revenues [(2)]	**$ (164)**	$ (76)	**$ (422)**	$ 396
Foreign Currency Derivatives:				
Foreign exchange	**9**	14	**(17)**	40
	$ (155)	$ (62)	**$ (439)**	$ 436
Total Realized and Unrealized Gains (Losses) on Risk Management, net				
Commodity and Other Derivatives:				
Revenues [(1) (2)]	**$ (241)**	$ (35)	**$ (517)**	$ 432
Transportation and processing	**-**	-	**-**	(4)
Foreign Currency Derivatives:				
Foreign exchange	**10**	23	**(6)**	48
	$ (231)	$ (12)	**$ (523)**	$ 476

(1) Includes realized gains of $2 million and $5 million for the three and nine months ended September 30, 2018, respectively, (2017 - gains of $2 million and $5 million, respectively) related to other derivative contracts.
(2) Includes unrealized losses of nil and $1 million for the three and nine months ended September 30, 2018, respectively, (2017 - losses of nil and $1 million, respectively) related to other derivative contracts.

Reconciliation of Unrealized Risk Management Positions from January 1 to September 30

	2018		2017
	Fair Value	**Total Unrealized Gain (Loss)**	Total Unrealized Gain (Loss)
Fair Value of Contracts, Beginning of Year	**$ 183**		
Change in Fair Value of Contracts in Place at Beginning of Year and Contracts Entered into During the Period	**(523)**	**$ (523)**	$ 476
Settlement of Other Derivative Contracts	**5**		
Fair Value of Contracts Realized During the Period	**84**	**84**	(40)
Fair Value of Contracts Outstanding	**$ (251)**	**$ (439)**	$ 436
Net Premiums Received on Unexpired Options	**(4)**		
Fair Value of Contracts and Net Premiums Received, End of Period	**$ (255)**		

Risk management assets and liabilities arise from the use of derivative financial instruments and are measured at fair value. See Note 18 for a discussion of fair value measurements.

Unrealized Risk Management Positions

		As at September 30, 2018		As at December 31, 2017
Risk Management Assets				
Current	**$**	**146**	$	205
Long-term		**132**		246
		278		451
Risk Management Liabilities				
Current		**450**		236
Long-term		**68**		13
		518		249
Other Derivative Contracts				
Current in accounts payable and accrued liabilities		**5**		5
Long-term in other liabilities and provisions		**10**		14
Net Risk Management Assets (Liabilities) and Other Derivative Contracts	**$**	**(255)**	$	183

C) Credit Risk

Credit risk arises from the potential that the Company may incur a loss if a counterparty to a financial instrument fails to meet its obligation in accordance with agreed terms. While exchange-traded contracts are subject to nominal credit risk due to the financial safeguards established by the New York Stock Exchange and the TSX, over-the-counter traded contracts expose Encana to counterparty credit risk. This credit risk exposure is mitigated through the use of credit policies approved by the Board of Directors governing the Company's credit portfolio including credit practices that limit transactions according to counterparties' credit quality. Mitigation strategies may include master netting arrangements, requesting collateral and/or transacting credit derivatives. The Company executes commodity derivative financial instruments under master agreements that have netting provisions that provide for offsetting payables against receivables. As a result of netting provisions, the Company's maximum exposure to loss under derivative financial instruments due to credit risk is limited to the net amounts due from the counterparties under the derivative contracts, as disclosed in Note 18. As at September 30, 2018, the Company had no significant credit derivatives in place and held no collateral.

As at September 30, 2018, cash equivalents include high-grade, short-term securities, placed primarily with financial institutions and companies with strong investment grade ratings. Any foreign currency agreements entered into are with major financial institutions that have investment grade credit ratings.

A substantial portion of the Company's accounts receivable are with customers in the oil and gas industry and are subject to normal industry credit risks. As at September 30, 2018, approximately 92 percent (92 percent as at December 31, 2017) of Encana's accounts receivable and financial derivative credit exposures were with investment grade counterparties.

As at September 30, 2018, Encana had two counterparties whose net settlement position individually accounted for more than 10 percent of the fair value of the outstanding in-the-money net risk management contracts by counterparty. As at September 30, 2018, these counterparties accounted for 69 percent and 11 percent of the fair value of the outstanding in-the-money net risk management contracts. As at December 31, 2017, Encana had three counterparties whose net settlement position accounted for 56 percent, 11 percent and 11 percent of the fair value of the outstanding in-the-money net risk management contracts.

During 2015 and 2017, Encana entered into agreements resulting from divestitures, which may require Encana to fulfill certain payment obligations on the take or pay volume commitments assumed by the purchasers. The circumstances that would require Encana to perform under the agreements include events where a purchaser fails to make payment to the guaranteed party and/or a purchaser is subject to an insolvency event. The agreements have remaining terms from three to six years with a fair value recognized of $15 million as at September 30, 2018 ($19 million as at December 31, 2017). The maximum potential amount of undiscounted future payments is $258 million as at September 30, 2018, and is considered unlikely.

20. Supplementary Information

Supplemental disclosures to the Condensed Consolidated Statement of Cash Flows are presented below:

A) Net Change in Non-Cash Working Capital

	Three Months Ended September 30,				Nine Months Ended September 30,			
		2018		2017		**2018**		2017
Operating Activities								
Accounts receivable and accrued revenues	**$**	**(8)**	$	(34)	**$**	**(152)**	$	69
Accounts payable and accrued liabilities		**59**		(82)		**99**		(253)
Income tax receivable and payable		**262**		214		**252**		(7)
	$	**313**	$	98	**$**	**199**	$	(191)

B) Non-Cash Activities

	Three Months Ended September 30,				Nine Months Ended September 30,			
		2018		2017		**2018**		2017
Non-Cash Investing Activities								
Asset retirement obligation incurred (See Note 12)	**$**	**3**	$	3	**$**	**13**	$	9
Property, plant and equipment accruals		**(20)**		(18)		**61**		60
Capitalized long-term incentives		**11**		30		**6**		30
Property additions/dispositions (swaps)		**55**		28		**195**		193
Non-Cash Financing Activities								
Common shares issued under dividend reinvestment plan (See Note 13)	**$**	**-**	$	1	**$**	**-**	$	1

21. Commitments and Contingencies

Commitments

The following table outlines the Company's commitments as at September 30, 2018:

	Expected Future Payments													
(undiscounted)		2018		2019		2020		2021		2022		Thereafter		Total
Transportation and Processing	$	146	$	709	$	688	$	598	$	571	$	2,763	**$**	**5,475**
Drilling and Field Services		73		66		29		9		-		-		**177**
Operating Leases		4		17		17		16		16		49		**119**
Total	$	223	$	792	$	734	$	623	$	587	$	2,812	**$**	**5,771**

Included within transportation and processing in the table above are certain commitments associated with midstream service agreements with VMLP as described in Note 15. Divestiture transactions can reduce certain commitments disclosed above.

Contingencies

Encana is involved in various legal claims and actions arising in the normal course of the Company's operations. Although the outcome of these claims cannot be predicted with certainty, the Company does not expect these matters to have a material adverse effect on Encana's financial position, cash flows or results of operations. Management's assessment of these matters may change in the future as certain of these matters are in early stages or are subject to a number of uncertainties. For material matters that the Company believes an unfavourable outcome is reasonably possible, the Company discloses the nature and a range of potential exposures. If an unfavourable outcome were to occur, there exists the possibility of a material impact on the Company's consolidated net earnings or loss for the period in which the effect becomes reasonably estimable. The Company accrues for such items when a liability is both probable and the amount can be reasonably estimated. Such accruals are based on the Company's information known about the matters, estimates of the outcomes of such matters and experience in handling similar matters.

22. Subsequent Events

Agreement to Acquire Newfield Exploration Company

On November 1, 2018, Encana announced that it has entered into a definitive merger agreement to acquire all of the issued and outstanding shares of common stock of Newfield Exploration Company ("Newfield") in an all-stock transaction. Under the terms of the merger agreement, Newfield shareholders will receive 2.6719 common shares of Encana for each share of Newfield common stock. The transaction has been unanimously approved by the Board of Directors of both Encana and Newfield and is subject to the terms and conditions set forth in the merger agreement. The transaction is expected to close in the first quarter of 2019.

Item 2. 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 unaudited interim Condensed Consolidated Financial Statements and accompanying notes for the period ended September 30, 2018 ("Consolidated Financial Statements"), which are included in Part I, Item 1 of this Quarterly Report on Form 10-Q and the audited Consolidated Financial Statements and accompanying notes and MD&A for the year ended December 31, 2017, which are included in Items 8 and 7, respectively, of the 2017 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 Quarterly Report on Form 10-Q. This MD&A includes the following sections:

- Executive Overview
- Results of Operations
- Liquidity and Capital Resources
- Non-GAAP Measures

Executive Overview

Strategy

Encana is a leading North American energy producer that is focused on developing its multi-basin portfolio of oil, NGLs and natural gas producing plays. Encana is committed to growing long-term shareholder value through a disciplined focus on generating profitable growth. The Company is pursuing the key business objectives of exercising a disciplined capital allocation strategy by investing in a limited number of core assets, growing high margin liquids volumes, maximizing profitability through operating efficiencies and reducing costs, and preserving balance sheet strength.

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.

Encana continually reviews and evaluates its strategy and changing market conditions. In 2018, Encana continues to focus on quality growth from high margin, scalable projects located in some of the best plays in North America, referred to as the "Core Assets", comprising Montney and Duvernay in Canada and Eagle Ford and Permian in the U.S. These world-class assets form a multi-basin portfolio enabling flexible and efficient investment of capital. The Company rapidly deploys successful ideas and practices across these assets, becoming more efficient as innovative and sustainable technical improvements are implemented.

For additional information on Encana's strategy, its reporting segments and the plays in which the Company operates, refer to Items 1 and 2 of the 2017 Annual Report on Form 10-K. 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 the first nine months of 2018, Encana focused on executing its 2018 capital plan, maintaining operational efficiencies achieved in 2017 and minimizing the effect of inflationary costs. Higher revenues in the first nine months of 2018 compared to 2017 resulting 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 40 percent and 35 percent, respectively. Liquids production volumes increased by 32 percent compared to 2017. Encana is 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

- Received approval from the TSX to purchase, for cancellation, up to 35 million common shares pursuant to a NCIB over a 12-month period from February 28, 2018 to February 27, 2019. As of September 30, 2018, the Company has purchased approximately 20.7 million common shares for total consideration of approximately $250 million.
- Completed the sale of the Company's Pipestone liquids hub in Alberta to Keyera Partnership, a subsidiary of Keyera Corp., announced on April 2, 2018. In conjunction with the sale, Keyera will own and construct a natural gas processing facility and 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

Three months ended September 30, 2018

- Reported net earnings of $39 million, including a net loss on risk management in revenues of $241 million, before tax.
- Generated cash from operating activities of $885 million, Non-GAAP Cash Flow of $589 million and Non-GAAP Cash Flow Margin of $16.93 per BOE.
- Paid dividends of $0.015 per common share.

Nine months ended September 30, 2018

- Reported net earnings of $39 million, including a net loss on risk management in revenues of $517 million, before tax, and a net foreign exchange loss of $93 million, before tax.
- Recovered current taxes of approximately $61 million and interest of $11 million primarily resulting from the resolution of certain tax items relating to prior taxation years.
- Generated cash from operating activities of $1,741 million, Non-GAAP Cash Flow of $1,575 million and Non-GAAP Cash Flow Margin of $16.63 per BOE, including the tax items noted above.
- Paid dividends of $0.045 per common share.
- Held cash and cash equivalents of $615 million and had available credit facilities of $4.0 billion for total liquidity of $4.6 billion at September 30, 2018.

Capital Investment

- Directed $350 million, or 67 percent, of total capital spending to Permian and Montney in the third quarter of 2018 and $1,163 million, or 72 percent, during the first nine months of 2018.
- Focused on highly efficient capital activity and short-cycle high margin projects providing flexibility to respond to fluctuations in commodity prices.

Production

Three months ended September 30, 2018

- Produced average oil and NGL volumes of 178.7 Mbbls/d which accounted for 47 percent of total production volumes. Average oil and plant condensate production volumes of 136.5 Mbbls/d were 76 percent of total liquids production volumes.
- Produced average natural gas volumes of 1,197 MMcf/d which accounted for 53 percent of total production volumes.

Nine months ended September 30, 2018

- Produced average oil and NGL volumes of 159.9 Mbbls/d which accounted for 46 percent of total production volumes. Average oil and plant condensate production volumes of 122.7 Mbbls/d were 77 percent of total liquids production volumes.
- Produced average natural gas volumes of 1,123 MMcf/d which accounted for 54 percent of total production volumes.

Revenues and Operating Expenses

- 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.
- Preserved operational efficiencies achieved in previous years and minimized the effect of inflationary costs.
- Incurred higher transportation and processing expense in the third quarter and the first nine months of 2018 of $79 million, or 40 percent, and $182 million, or 29 percent, respectively, compared to the same periods in 2017 primarily due to higher volumes in Montney and Permian, and additional costs incurred in conjunction with the diversification of other downstream markets to capture higher realized prices.

Subsequent Events

On November 1, 2018, Encana announced that it has entered into a definitive merger agreement to acquire all of the issued and outstanding shares of common stock of Newfield Exploration Company ("Newfield") in an all-stock transaction. Under the terms of the merger agreement, Newfield shareholders will receive 2.6719 common shares of Encana for each share of Newfield common stock. The transaction has been unanimously approved by the Board of Directors of both Encana and Newfield and is subject to the terms and conditions set forth in the merger agreement. The transaction is expected to close in the first quarter of 2019.

On October 1, 2018, Encana announced an agreement to sell its San Juan assets, comprising approximately 182,000 net acres in New Mexico, to DJR Energy, LLC for total consideration of approximately $480 million. The transaction is expected to close in the fourth quarter of 2018, with an effective date of April 1, 2018, and is subject to the satisfaction of normal closing conditions and customary closing adjustments.

2018 Outlook

Industry Outlook

The oil and gas industry is cyclical and commodity prices are inherently volatile. Oil prices for the remainder of 2018 are expected to reflect global supply and demand dynamics as well as the geopolitical environment. The original OPEC agreement implemented in 2017 to limit output and the drawdowns of oil storage inventory levels were generally supportive of oil prices in the first half of 2018. Trade disputes and oil supply outages in recent months resulting from geopolitical instability in major producing countries has created additional uncertainty for oil and gas supply which could impact prices for the remainder of the year. As well, prices could be impacted as a result of decisions made by OPEC and certain non-OPEC countries to increase future oil production. OPEC and certain non-OPEC countries are expected to meet again in December 2018 to review production levels and decide on a framework for permanent cooperation with allied producers to seek a balanced and sustainable global oil market. The result of this meeting could further contribute to price fluctuations in 2019.

Natural gas prices in 2018 will be affected by the timing of supply and demand growth and the effects of weather. Natural gas prices in western Canada have seen significant negative price pressure as supply reached multi-year highs, surpassing regional demand and stressing effective pipeline capacity. Relatively strong condensate prices may also lend support to activity levels resulting in continued downward pressure on natural gas prices for the remainder of 2018. Potential for improvement in U.S. natural gas prices remains limited due to continued substantial production increases in 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. 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 September 30, 2018, the Company has hedged approximately 137 Mbbls/d of expected oil and condensate production and 1,017 MMcf/d of expected natural gas production for the remainder of the year. Additional information on Encana's hedging program can be found in Note 19 to the Consolidated Financial Statements included in Part I, Item 1 of this Quarterly Report on Form 10-Q.

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 is experiencing wider differentials due to temporary local export capacity constraints. 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 2018 and 2019. In addition, Encana continues to seek new markets to yield higher returns.

The Company released updated Corporate Guidance on November 1, 2018, revising its guidance range downward for transportation and processing expense from $7.40 to $7.75 per BOE to $7.20 to $7.40 per BOE to reflect lower cost structures than anticipated. The Company also updated its full year capital investment guidance to approximately $2.0 billion from the previous guidance range of $1.8 to $1.9 billion reflecting higher costs associated with diesel fuel, steel tariffs and delays in sourcing local sand in Eagle Ford. The updated full year capital investment guidance of approximately $2.0 billion includes current year expenditures on the Pipestone liquids hub and the San Juan assets totaling approximately $55 million. The liquids hub divestiture and previously announced sale of the San Juan assets are expected to generate proceeds totaling approximately $515 million.

Encana's updated 2018 Corporate Guidance can be accessed on the Company's website at www.encana.com.

Capital Investment

Encana is on track to meet its updated full year capital investment guidance of approximately $2.0 billion. During the first nine months of 2018, the Company spent $1.6 billion, of which $718 million was directed to Permian where the Company has drilled 81 net wells and $445 million was directed to Montney with 108 net wells drilled. Capital investment in Permian is expected to be optimized by Encana's cube development approach to maximize returns and recovery. Capital investment in Montney is allocated to both Cutbank Ridge and Pipestone with a focus on growing condensate volumes. The remainder of the capital investment, primarily directed to Eagle Ford and Duvernay, is expected to optimize production and margins.

Encana continually strives to improve well performance by lowering drilling and completion costs through innovative techniques. Encana's large-scale cube development model utilizes multi-well pads and advanced completion designs to access stacked pay resource to maximize returns and resource recovery from its reservoirs. 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. During the first nine months of 2018, average liquids production volumes were 159.9 Mbbls/d and average natural gas production volumes were 1,123 MMcf/d. The Company expects to deliver substantial liquids growth for the remainder of the year. The Company is on track to meet the full year 2018 guidance ranges for liquids production volumes of 165.0 Mbbls/d to 175.0 Mbbls/d and natural gas production volumes of 1,150 MMcf/d to 1,250 MMcf/d by year end as a result of the Company's growth plans for Montney. Encana's growth plans for Montney are supported by third party processing plants commissioned in 2017 and the second quarter of 2018, as well as the completion of the Pipestone liquids hub at the end of the third quarter.

Operating Expenses

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. As activity in the industry accelerates, Encana expects to continue pursuing innovative ways to reduce upstream operating and administrative expenses. Operating costs in the first nine months of 2018 are on track to meet the full year updated 2018 guidance ranges. Transportation and processing expense was $7.39 per BOE, while upstream operating expense and administrative expense, excluding long-term incentive costs, were $3.35 per BOE and $1.34 per BOE, respectively.

Service costs are expected to increase with higher activity in the oil and gas industry and the recovery of liquids prices. Encana strives to offset any inflationary pressures with efficiency improvements and effective supply chain management, including favorable price negotiations.

Results of Operations

Selected Financial Information

($ millions)	Three months ended September 30, 2018	Three months ended September 30, 2017 (1)	Nine months ended September 30, 2018	Nine months ended September 30, 2017 (1)
Product and Service Revenues				
Upstream product revenues	**$ 1,166**	$ 652	**$ 3,107**	$ 2,119
Market optimization	**317**	224	**909**	614
Service revenues	**5**	4	**9**	18
Total Product and Service Revenues	**1,488**	880	**4,025**	2,751
Gains (Losses) on Risk Management, Net	**(241)**	(35)	**(517)**	432
Sublease Revenues	**15**	16	**50**	50
Total Revenues	**1,262**	861	**3,558**	3,233
Total Operating Expenses (2)	**1,143**	865	**3,218**	2,427
Operating Income (Loss)	**119**	(4)	**340**	806
Total Other (Income) Expenses	**74**	(526)	**356**	(477)
Net Earnings (Loss) Before Income Tax	**45**	522	**(16)**	1,283
Income Tax Expense (Recovery)	**6**	228	**(55)**	227
Net Earnings (Loss)	**$ 39**	$ 294	**$ 39**	$ 1,056

(1) 2017 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 2 to the Consolidated Financial Statements included in Part I, Item 1 of this Quarterly Report on Form 10-Q.
(2) Total Operating Expenses include non-cash items such as DD&A, 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 revenue, 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)	Three months ended September 30, 2018	Three months ended September 30, 2017	Nine months ended September 30, 2018	Nine months ended September 30, 2017
Oil & NGLs				
WTI ($/bbl)	**$ 69.50**	$ 48.21	**$ 66.75**	$ 49.47
Edmonton Condensate (C$/bbl)	**$ 87.34**	$ 59.59	**$ 85.30**	$ 64.62
Natural Gas				
NYMEX ($/MMBtu)	**$ 2.90**	$ 3.00	**$ 2.90**	$ 3.17
AECO (C$/Mcf)	**$ 1.35**	$ 2.04	**$ 1.41**	$ 2.58
Dawn (C$/MMBtu)	**$ 3.79**	$ 3.62	**$ 3.73**	$ 4.01

Production Volumes and Realized Prices

	Three months ended September 30,				Nine months ended September 30,			
	Production Volumes (1)		Realized Prices (2)		Production Volumes (1)		Realized Prices (2)	
	2018	2017	**2018**	2017	**2018**	2017	**2018**	2017
Oil (Mbbls/d, $/bbl)								
Canadian Operations	**0.3**	0.6	**$ 60.32**	$ 31.66	**0.4**	0.5	**$ 57.83**	$ 37.25
USA Operations	**95.2**	74.6	**66.84**	45.78	**87.3**	72.9	**65.66**	47.07
Total	**95.5**	75.2	**66.82**	45.66	**87.7**	73.4	**65.62**	47.01
NGLs – Plant Condensate (Mbbls/d, $/bbl)								
Canadian Operations	**36.3**	22.8	**64.82**	46.41	**31.2**	20.7	**64.61**	47.74
USA Operations	**4.7**	5.1	**55.23**	36.63	**3.8**	3.1	**55.12**	38.95
Total	**41.0**	27.9	**63.73**	44.61	**35.0**	23.8	**63.60**	46.59
NGLs – Other (Mbbls/d, $/bbl)								
Canadian Operations	**14.4**	4.5	**30.25**	22.68	**12.5**	4.7	**28.87**	21.47
USA Operations	**27.8**	19.9	**28.27**	18.37	**24.7**	19.3	**24.08**	18.11
Total	**42.2**	24.4	**28.95**	19.16	**37.2**	24.0	**25.69**	18.77
Total NGLs (Mbbls/d, $/bbl)								
Canadian Operations	**50.7**	27.3	**54.99**	42.52	**43.7**	25.4	**54.41**	42.84
USA Operations	**32.5**	25.0	**32.15**	22.13	**28.5**	22.4	**28.16**	21.01
Total	**83.2**	52.3	**46.07**	32.75	**72.2**	47.8	**44.07**	32.61
Total Oil & NGLs (Mbbls/d, $/bbl)								
Canadian Operations	**51.0**	27.9	**55.03**	42.28	**44.1**	25.9	**54.44**	42.74
USA Operations	**127.7**	99.6	**58.01**	39.83	**115.8**	95.3	**56.45**	40.95
Total	**178.7**	127.5	**57.16**	40.37	**159.9**	121.2	**55.90**	41.33
Natural Gas (MMcf/d, $/Mcf)								
Canadian Operations	**1,038**	736	**1.96**	1.73	**975**	802	**2.09**	2.21
USA Operations	**159**	203	**2.19**	2.90	**148**	306	**2.25**	3.10
Total	**1,197**	939	**1.99**	1.98	**1,123**	1,108	**2.11**	2.46
Total Production (MBOE/d, $/BOE)								
Canadian Operations	**224.1**	150.4	**21.62**	16.29	**206.5**	159.5	**21.46**	18.06
USA Operations	**154.1**	133.6	**50.30**	34.13	**140.5**	146.3	**48.90**	33.15
Total	**378.2**	284.0	**33.30**	24.67	**347.0**	305.8	**32.57**	25.28
Production Mix (%)								
Oil & Plant Condensate	**36**	36			**35**	32		
NGLs – Other	**11**	9			**11**	8		
Total Oil & NGLs	**47**	45			**46**	40		
Natural Gas	**53**	55			**54**	60		
Core Assets Production								
Oil (Mbbls/d)	**93.5**	71.9			**85.5**	69.3		
NGLs – Plant Condensate (Mbbls/d)	**40.8**	27.4			**34.9**	23.2		
NGLs – Other (Mbbls/d)	**41.1**	22.9			**36.0**	22.3		
Total NGLs (Mbbls/d)	**81.9**	50.3			**70.9**	45.5		
Total Oil & NGLs (Mbbls/d)	**175.4**	122.2			**156.4**	114.8		
Natural Gas (MMcf/d)	**1,138**	754			**1,054**	775		
Total Production (MBOE/d)	**364.9**	248.0			**332.0**	244.0		
% of Total Encana Production	**96**	87			**96**	80		

(1) Average daily.
(2) Average per-unit prices, excluding the impact of risk management activities.

Upstream Product Revenues

($ millions)	Three months ended September 30, Oil	NGLs [1]	Natural Gas [2]	Total	Nine months ended September 30, Oil	NGLs [1]	Natural Gas [2]	Total
2017 Upstream Product Revenues	**$ 317**	**$ 156**	**$ 173**	**$ 646**	**$ 942**	**$ 425**	**$ 745**	**$ 2,112**
Increase (decrease) due to:								
Sales prices	184	92	10	286	445	195	(59)	581
Production volumes	86	106	36	228	185	248	(39)	394
2018 Upstream Product Revenues	**$ 587**	**$ 354**	**$ 219**	**$ 1,160**	**$ 1,572**	**$ 868**	**$ 647**	**$ 3,087**

(1) Includes plant condensate.
(2) Natural gas revenues for the third quarter and the first nine months of 2018 exclude a royalty adjustment with no associated production volumes of $6 million and $20 million, respectively (2017 - $6 million and $7 million, respectively).

Oil Revenues

Three months ended September 30, 2018 versus September 30, 2017

Oil revenues increased $270 million compared to the third quarter of 2017 primarily due to:

- Higher average realized oil prices of $21.16 per bbl, or 46 percent, increased revenues by $184 million. The increase reflected a higher WTI benchmark price which was up 44 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 in USA Operations; and
- Higher average oil production volumes of 20.3 Mbbls/d increased revenues by $86 million. Higher volumes were primarily due to a successful drilling program in Permian (24.3 Mbbls/d), partially offset by natural declines in Eagle Ford (3.0 Mbbls/d).

Nine months ended September 30, 2018 versus September 30, 2017

Oil revenues increased $630 million compared to the first nine months of 2017 primarily due to:

- Higher average realized oil prices of $18.61 per bbl, or 40 percent, increased revenues by $445 million. The increase reflected a higher WTI benchmark price which was up 35 percent and exposure to other downstream benchmark prices in 2018 resulting from the diversification of the Company's markets; and
- Higher average oil production volumes of 14.3 Mbbls/d increased revenues by $185 million. Higher volumes were primarily due to a successful drilling program in Permian (20.5 Mbbls/d), partially offset by natural declines in Eagle Ford (3.8 Mbbls/d) and asset sales (1.2 Mbbls/d), which mainly include the Tuscaloosa Marine Shale assets in the second quarter of 2017 and the Piceance natural gas assets in the third quarter of 2017.

NGL Revenues

Three months ended September 30, 2018 versus September 30, 2017

NGL revenues increased $198 million compared to the third quarter of 2017 primarily due to:

- Higher average realized NGL prices of $13.32 per bbl, or 41 percent, increased revenues by $92 million. The increase reflected higher WTI and Edmonton Condensate benchmark prices which were up 44 percent and 47 percent, respectively, as well as benchmark prices for other NGLs; and
- Higher average NGL production volumes of 30.9 Mbbls/d increased revenues by $106 million. Higher volumes were due to successful drilling programs in Montney and Permian (36.1 Mbbls/d), partially offset by natural declines in Duvernay and Eagle Ford (3.6 Mbbls/d).

Nine months ended September 30, 2018 versus September 30, 2017

NGL revenues increased $443 million compared to the first nine months of 2017 primarily due to:

- Higher average realized NGL prices of $11.46 per bbl, or 35 percent, increased revenues by $195 million. The increase reflected higher WTI and Edmonton Condensate benchmark prices which were up 35 percent and 32 percent, respectively, as well as benchmark prices for other NGLs; and
- Higher average NGL production volumes of 24.4 Mbbls/d increased revenues by $248 million. Higher volumes were primarily due to successful drilling programs in Montney and Permian (29.7 Mbbls/d), partially offset by natural declines in Duvernay (2.1 Mbbls/d), increased downtime resulting from scheduled plant maintenance for processing liquids rich volumes in Montney (1.2 Mbbls/d) and asset sales (1.1 Mbbls/d), 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.

Natural Gas Revenues

Three months ended September 30, 2018 versus September 30, 2017

Natural gas revenues increased $46 million compared to the third quarter of 2017 primarily due to:

- Slightly higher average realized natural gas prices of $0.01 per Mcf, or one percent, increased revenues by $10 million. The increase reflected exposure to other downstream benchmark prices in 2018 resulting from the diversification of the Company's markets, partially offset by lower NYMEX and AECO benchmark prices which were down three percent and 34 percent, respectively, and lower regional pricing in USA Operations; and
- Higher average natural gas production volumes of 258 MMcf/d increased revenues by $36 million. Higher volumes were due to successful drilling programs in Montney and Permian (347 MMcf/d) and decreased downtime primarily resulting from scheduled plant maintenance in Montney in 2017 (54 MMcf/d), partially offset by asset sales (121 MMcf/d), which mainly included certain assets in Wheatland in the fourth quarter of 2017 and the Piceance natural gas assets in the third quarter of 2017, and natural declines in Duvernay (12 MMcf/d) and in Other Upstream Operations (11 MMcf/d) in the third quarter of 2018.

Nine months ended September 30, 2018 versus September 30, 2017

Natural gas revenues decreased $98 million compared to the first nine months of 2017 primarily due to:

- Lower average realized natural gas prices of $0.35 per Mcf, or 14 percent, decreased revenues by $59 million. The decrease reflected lower NYMEX and AECO benchmark prices which were down nine percent and 45 percent, respectively, as well as lower regional pricing in USA Operations, partially offset by exposure to other downstream benchmark prices in 2018 resulting from the diversification of the Company's markets; and
- Production volume changes decreased revenues by $39 million resulting from:
    - Lower production volumes in the USA Operations (158 MMcf/d) decreased revenues by $134 million primarily due to the sale of the Piceance natural gas assets in the third quarter of 2017 (173 MMcf/d), partially offset by a successful drilling program in Permian in 2018 (25 MMcf/d).
    - Higher production volumes in Canadian Operations (173 MMcf/d) increased revenues by $95 million resulting from a successful drilling program in Montney (242 MMcf/d) and decreased downtime resulting from scheduled plant maintenance in Montney in 2017 (27 MMcf/d), partially offset by asset sales (66 MMcf/d), which mainly include certain assets in Wheatland in the fourth quarter of 2017, and lower volumes in Other Upstream Operations (30 MMcf/d).

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 September 30, 2018 can be found in Note 19 to the Consolidated Financial Statements included in Part I, Item 1 of this Quarterly Report on Form 10-Q.

The following tables provide the effects of Encana's risk management activities on revenues.

	Three months ended September 30,				Nine months ended September 30,			
($ millions)		**2018**		2017		**2018**		2017
Realized Gains (Losses) on Risk Management								
Commodity Price (1)								
Oil	**$**	**(87)**	$	14	**$**	**(208)**	$	30
NGLs (2)		**(47)**		4		**(105)**		5
Natural Gas		**56**		21		**216**		(4)
Other (3)		**1**		2		**2**		5
Total		**(77)**		41		**(95)**		36
Unrealized Gains (Losses) on Risk Management		**(164)**		(76)		**(422)**		396
Total Gains (Losses) on Risk Management, Net	**$**	**(241)**	$	(35)	**$**	**(517)**	$	432

	Three months ended September 30,				Nine months ended September 30,			
(Per-unit)		**2018**		2017		**2018**		2017
Realized Gains (Losses) on Risk Management								
Commodity Price (1)								
Oil ($/bbl)	**$**	**(9.77)**	$	2.12	**$**	**(8.68)**	$	1.51
NGLs ($/bbl) (2)	**$**	**(6.21)**	$	0.58	**$**	**(5.32)**	$	0.33
Natural Gas ($/Mcf)	**$**	**0.51**	$	0.25	**$**	**0.70**	$	(0.01)
Total ($/BOE)	**$**	**(2.23)**	$	1.50	**$**	**(1.02)**	$	0.37

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

	Three months ended September 30,				Nine months ended September 30,			
($ millions)		**2018**		2017		**2018**		2017
Market Optimization	**$**	**317**	$	224	**$**	**909**	$	614

Three months ended September 30, 2018 versus September 30, 2017

Market Optimization revenues increased $93 million compared to the third quarter of 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 the Company's previous divestitures ($137 million), partially offset by lower natural gas benchmark prices ($44 million).

Nine months ended September 30, 2018 versus September 30, 2017

Market Optimization revenues increased $295 million compared to the first nine months of 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 the Company's previous divestitures ($472 million), partially offset by lower natural gas benchmark prices ($177 million).

Sublease Revenues

Sublease revenues primarily include 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 11 to the Consolidated Financial Statements included in Part I, Item 1 of this Quarterly Report on Form 10-Q.

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.

	Three months ended September 30,		Nine months ended September 30,	
($ millions)	**2018**	2017	**2018**	2017
Canadian Operations	**$ 4**	$ 6	**$ 12**	$ 16
USA Operations	**41**	21	**97**	64
Total	**$ 45**	$ 27	**$ 109**	$ 80

	Three months ended September 30,		Nine months ended September 30,	
($/BOE)	**2018**	2017	**2018**	2017
Canadian Operations	**$ 0.20**	$ 0.42	**$ 0.22**	$ 0.37
USA Operations	**$ 2.91**	$ 1.69	**$ 2.53**	$ 1.59
Total	**$ 1.31**	$ 1.01	**$ 1.15**	$ 0.95

Three months ended September 30, 2018 versus September 30, 2017

Production, mineral and other taxes increased $18 million compared to the third quarter of 2017 primarily due to:

- Higher liquids prices in Permian and Eagle Ford and higher production volumes in Permian ($19 million) and lower production taxes in 2017 from tax recoveries in the USA Operations ($4 million);

partially offset by:

- Asset sales ($3 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 and lower natural gas prices ($2 million).

Nine months ended September 30, 2018 versus September 30, 2017

Production, mineral and other taxes increased $29 million compared to the first nine months of 2017 primarily due to:

- Higher liquids prices in Permian and Eagle Ford and higher production volumes in Permian ($36 million) and lower production taxes in 2017 from tax recoveries in the USA Operations ($6 million);

partially offset by:

- Asset sales ($14 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.

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.

	Three months ended September 30,				Nine months ended September 30,			
($ millions)		**2018**		2017		**2018**		2017
Canadian Operations	**$**	**211**	$	138	**$**	**608**	$	403
USA Operations		**34**		31		**92**		141
Upstream Transportation and Processing		**245**		169		**700**		544
Market Optimization		**33**		30		**99**		73
Total	**$**	**278**	$	199	**$**	**799**	$	617

	Three months ended September 30,				Nine months ended September 30,			
($/BOE)		**2018**		2017		**2018**		2017
Canadian Operations	**$**	**10.26**	$	10.00	**$**	**10.78**	$	9.26
USA Operations	**$**	**2.38**	$	2.55	**$**	**2.39**	$	3.53
Upstream Transportation and Processing	**$**	**7.05**	$	6.50	**$**	**7.39**	$	6.52

Three months ended September 30, 2018 versus September 30, 2017

Transportation and processing expense increased $79 million compared to the third quarter of 2017 primarily due to:

- Higher volumes and gathering and processing fees in Montney and Permian ($51 million), higher downstream processing and transportation costs due to higher volumes primarily in Montney and Permian and costs relating to the diversification of the Company's downstream markets ($48 million);

partially offset by:

- Asset sales ($11 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 the lower U.S./Canadian dollar exchange rate ($6 million).

Nine months ended September 30, 2018 versus September 30, 2017

Transportation and processing expense increased $182 million compared to the first nine months of 2017 primarily due to:

- Higher volumes and gathering and processing fees in Montney and Permian ($125 million), higher downstream processing and transportation costs due to higher volumes primarily in Montney and Permian and costs relating to the diversification of the Company's downstream markets ($139 million) and the higher U.S./Canadian dollar exchange rate ($6 million);

partially offset by:

- Asset sales ($71 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 in Other Upstream Operations ($16 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)	Three months ended September 30, **2018**	Three months ended September 30, 2017	Nine months ended September 30, **2018**	Nine months ended September 30, 2017
Canadian Operations	**$ 34**	$ 36	**$ 98**	$ 89
USA Operations	**80**	81	**238**	252
Upstream Operating Expense	**114**	117	**336**	341
Market Optimization	**8**	11	**25**	23
Corporate & Other	**2**	4	**11**	13
Total	**$ 124**	$ 132	**$ 372**	$ 377

($/BOE)	Three months ended September 30, **2018**	Three months ended September 30, 2017	Nine months ended September 30, **2018**	Nine months ended September 30, 2017
Canadian Operations	**$ 1.61**	$ 2.50	**$ 1.70**	$ 1.97
USA Operations	**$ 5.56**	$ 6.57	**$ 6.16**	$ 6.17
Upstream Operating Expense (1)	**$ 3.22**	$ 4.41	**$ 3.51**	$ 3.98

(1) Upstream Operating Expense per BOE for the third quarter and first nine months of 2018 includes long-term incentive costs of $0.15/BOE and $0.16/BOE, respectively (2017 - $0.45/BOE and $0.13/BOE, respectively).

Three months ended September 30, 2018 versus September 30, 2017

Operating expense decreased $8 million compared to the third quarter of 2017 primarily due to:

- Lower long-term incentive costs in 2018 resulting from the smaller change in Encana's share price in the third quarter of 2018 compared to 2017 ($10 million) and asset sales ($8 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 ($13 million).

Nine months ended September 30, 2018 versus September 30, 2017

Operating expense decreased $5 million compared to the first nine months of 2017 primarily due to:

- Asset sales ($43 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 ($35 million) and higher long-term incentive costs resulting from the increase in Encana's share price in the first nine months of 2018 ($6 million).

Further information on Encana's long-term incentives can be found in Note 16 to the Consolidated Financial Statements included in Part I, Item 1 of this Quarterly Report on Form 10-Q.

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)	Three months ended September 30, 2018	2017	Nine months ended September 30, 2018	2017
Market Optimization	**$ 282**	$ 202	**$ 803**	$ 565

Three months ended September 30, 2018 versus September 30, 2017

Purchased product expense increased $80 million compared to the third quarter of 2017 primarily due to:

- Higher third-party volumes purchased, primarily related to natural gas, for optimization activities and long-term marketing arrangements associated with the Company's previous divestitures ($131 million), partially offset by lower natural gas benchmark prices ($51 million).

Nine months ended September 30, 2018 versus September 30, 2017

Purchased product expense increased $238 million compared to the first nine months of 2017 primarily due to:

- Higher third-party volumes purchased, primarily related to natural gas, for optimization activities and long-term marketing arrangements associated with the Company's previous divestitures ($444 million), partially offset by lower natural gas benchmark prices ($206 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 the 2017 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 the MD&A included in Item 7 of the 2017 Annual Report on Form 10-K. Corporate assets are carried at cost and depreciated on a straight-line basis over the estimated service lives of the assets.

($ millions)	Three months ended September 30, 2018	2017	Nine months ended September 30, 2018	2017
Canadian Operations	**$ 95**	$ 53	**$ 257**	$ 170
USA Operations	**241**	139	**628**	368
Upstream DD&A	**336**	192	**885**	538
Market Optimization	**-**	1	**1**	1
Corporate & Other	**13**	17	**38**	51
Total	**$ 349**	$ 210	**$ 924**	$ 590

($/BOE)	Three months ended September 30, 2018	2017	Nine months ended September 30, 2018	2017
Canadian Operations	**$ 4.57**	$ 3.84	**$ 4.55**	$ 3.89
USA Operations	**$ 17.05**	$ 11.31	**$ 16.39**	$ 9.22
Upstream DD&A	**$ 9.65**	$ 7.35	**$ 9.34**	$ 6.44

Three months ended September 30, 2018 versus September 30, 2017

DD&A increased $139 million compared to the third quarter of 2017 primarily due to:

- Higher depletion rates in the USA and Canadian Operations ($79 million and $23 million, respectively) and higher volumes in the USA and Canadian Operations ($24 million and $22 million, respectively).

The depletion rates in the Canadian and USA Operations increased $0.73 per BOE and $5.74 per BOE, respectively, compared to the third quarter of 2017 primarily due to:

- Higher capital spending resulting from an increased capital program in 2018 and transfers of unproved property costs of previously acquired assets which have been evaluated for proved reserves.

Nine months ended September 30, 2018 versus September 30, 2017

DD&A increased $334 million compared to the first nine months of 2017 primarily due to:

- Higher depletion rates in the USA and Canadian Operations ($265 million and $42 million, respectively) and higher volumes in the Canadian Operations ($42 million).

The depletion rates in the Canadian and USA Operations increased $0.66 per BOE and $7.17 per BOE, respectively, compared to the first nine months of 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.

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.

	Three months ended September 30,		Nine months ended September 30,	
	2018	2017	**2018**	2017
Administrative ($ millions)	**$ 57**	$ 86	**$ 187**	$ 168
Administrative ($/BOE) (1)	**$ 1.64**	$ 3.31	**$ 1.98**	$ 2.02

(1) Administrative expense per BOE for the third quarter and first nine months of 2018 includes long-term incentive costs of $0.47/BOE and $0.64/BOE, respectively (2017 - $1.68/BOE and $0.44/BOE, respectively).

Three months ended September 30, 2018 versus September 30, 2017

Administrative expense in the third quarter of 2018 decreased $29 million compared to the third quarter of 2017 primarily due to lower long-term incentive costs in 2018 resulting from the smaller change in Encana's share price in the third quarter of 2018 compared to 2017 ($26 million).

Nine months ended September 30, 2018 versus September 30, 2017

Administrative expense in the first nine months of 2018 increased $19 million compared to the first nine months of 2017 primarily due to higher long-term incentive costs resulting from the increase in Encana's share price in the first nine months of 2018 ($25 million), partially offset by legal costs incurred in 2017 ($5 million).

Other (Income) Expenses

($ millions)	Three months ended September 30, 2018	2017	Nine months ended September 30, 2018	2017
Interest	$ 92	$ 101	$ 265	$ 268
Foreign exchange (gain) loss, net	(23)	(210)	93	(294)
(Gain) loss on divestitures, net	-	(406)	(4)	(405)
Other (gains) losses, net	5	(11)	2	(46)
Total Other (Income) Expenses	$ 74	$ (526)	$ 356	$ (477)

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 obligation for The Bow office building and capital leases. Further details on changes in interest can be found in Note 5 to the Consolidated Financial Statements included in Part I, Item 1 of this Quarterly Report on Form 10-Q.

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 6 to the Consolidated Financial Statements included in Part I, Item 1 of this Quarterly Report on Form 10-Q. Additional information on foreign exchange rates and the effects of foreign exchange rate changes can be found in Item 3 of this Quarterly Report on Form 10-Q.

In the third quarter of 2018, Encana recorded a lower net foreign exchange gain compared to 2017 ($187 million). The change was primarily due to lower unrealized foreign exchange gains on the translation of U.S. dollar financing debt issued from Canada compared to 2017 ($113 million) and unrealized foreign exchange losses on the translation of intercompany notes compared to gains in 2017 ($64 million).

In the first nine months of 2018, Encana recorded a net foreign exchange loss compared to a net gain in 2017 ($387 million). The change 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 ($403 million) and losses on the translation of U.S. dollar risk management contracts issued from Canada compared to gains in 2017 ($60 million), partially offset by realized foreign exchange gains on the settlement of intercompany notes compared to losses in 2017 ($65 million).

(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 on gains on divestitures can be found in Note 8 to the Consolidated Financial Statements included in Part I, Item 1 of this Quarterly Report on Form 10-Q.

Gain on divestitures in the third quarter and first nine months of 2017 primarily includes the before tax gain on the sale of the Piceance natural gas assets. Further information on divestitures can be found in the Liquidity and Capital Resources section of this MD&A.

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.

Other gains in the first nine months of 2017 primarily includes 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.

Income Tax

($ millions)	Three months ended September 30, 2018	2017	Nine months ended September 30, 2018	2017
Current Income Tax Expense (Recovery)	**$ -**	$ 1	**$ (61)**	$ (56)
Deferred Income Tax Expense (Recovery)	**6**	227	**6**	283
Income Tax Expense (Recovery)	**$ 6**	$ 228	**$ (55)**	$ 227
Effective Tax Rate	**13.3%**	43.7%	**343.8%**	17.7%

Income Tax Expense (Recovery)

Three months ended September 30, 2018 versus September 30, 2017

In the third quarter of 2018, Encana recorded a lower income tax expense compared to 2017 primarily due to a lower deferred tax expense as a result of:

- Lower net earnings before income tax in 2018 compared to 2017;
- A reduction in the U.S. federal corporate tax rate to 21 percent from 35 percent resulting from U.S. Tax Reform; and
- Changes in the estimated annual effective income tax rate in 2017 arising from gains recognized on foreign exchange and divestitures, including allocated goodwill.

Nine months ended September 30, 2018 versus September 30, 2017

In the first nine months of 2018, Encana recorded a lower deferred income tax expense compared to 2017 primarily due to lower net earnings before income tax compared to 2017 and U.S. Tax Reform, as discussed above. The deferred tax expense in the first nine months of 2017 was primarily due to changes in the estimated annual effective income tax rate as discussed above.

There has been no change in 2018 to the provisional tax adjustment 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. Additional information on U.S. Tax Reform can be found in Note 7 to the Consolidated Financial Statements included in Item 8 of the 2017 Annual Report on Form 10-K.

Effective Tax Rate

Encana's interim income tax expense is determined using the 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, 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. These items resulted in an effective tax rate for the third quarter of 2018 which is lower than the Canadian statutory rate of 27 percent and an effective tax rate for the first nine months of 2018 that is above the Canadian statutory rate.

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 September 30, 2018, $229 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.

	As at September 30,	
($ millions, except as indicated)	**2018**	2017
Cash and Cash Equivalents	**$ 615**	$ 889
Available Credit Facility – Encana (1)	**2,500**	3,000
Available Credit Facility – U.S. Subsidiary (1)	**1,500**	1,500
Total Liquidity	**$ 4,615**	$ 5,389
Long-Term Debt, including current portion	**$ 4,198**	$ 4,197
Total Shareholders' Equity	**$ 6,494**	$ 6,965
Debt to Capitalization (%) (2)	**39**	38
Debt to Adjusted Capitalization (%) (3)	**23**	22

(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 12 to the Consolidated Financial Statements included in Item 8 of the 2017 Annual Report on Form 10-K.

Sources and Uses of Cash

In the third quarter and first nine months of 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	Three months ended September 30, 2018	Three months ended September 30, 2017	Nine months ended September 30, 2018	Nine months ended September 30, 2017
Sources of Cash and Cash Equivalents					
Cash from operating activities	Operating	**$ 885**	$ 357	**$ 1,741**	$ 681
Proceeds from divestitures	Investing	**24**	625	**89**	710
Other	Investing	**-**	14	**72**	93
		909	996	**1,902**	1,484
Uses of Cash and Cash Equivalents					
Capital expenditures	Investing	**523**	473	**1,626**	1,287
Acquisitions	Investing	**15**	2	**17**	50
Purchase of common shares	Financing	**50**	-	**250**	-
Dividends on common shares	Financing	**14**	14	**43**	43
Other	Investing/Financing	**31**	21	**68**	61
		633	510	**2,004**	1,441
Foreign Exchange Gain (Loss) on Cash and Cash Equivalents Held in Foreign Currency		**3**	8	**(2)**	12
Increase (Decrease) in Cash and Cash Equivalents		**$ 279**	$ 494	**$ (104)**	$ 55

Operating Activities

Cash from operating activities in the third quarter and first nine months of 2018 was $885 million and $1,741 million, respectively, and was primarily a reflection of recovering liquids prices, increases in production volumes, 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 20 to the Consolidated Financial Statements included in Part I, Item 1 of this Quarterly Report on Form 10-Q. Encana expects it will continue to meet the payment terms of its suppliers.

Non-GAAP Cash Flow in the third quarter and first nine months of 2018 was $589 million and $1,575 million, respectively. Non-GAAP Cash Flow 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.

Three months ended September 30, 2018 versus September 30, 2017

Net cash from operating activities increased $528 million compared to the third quarter of 2017 primarily due to:

- Higher realized commodity prices ($286 million), higher production volumes ($228 million) and changes in non-cash working capital ($215 million);

partially offset by:

- Realized losses on risk management in revenues in the third quarter of 2018 compared to realized gains in 2017 ($118 million) and higher transportation and processing expense ($79 million).

Nine months ended September 30, 2018 versus September 30, 2017

Net cash from operating activities increased $1,060 million compared to the first nine months of 2017 primarily due to:

- Higher realized commodity prices ($581 million), higher production volumes ($394 million) and changes in non-cash working capital ($390 million);

partially offset by:

- Higher transportation and processing expense ($182 million), realized losses on risk management in revenues in the first nine months of 2018 compared to realized gains in 2017 ($131 million) and lower interest income recorded in other gains ($27 million).

Investing Activities

Cash used in investing activities in the first nine months of 2018 was $1,482 million primarily due to capital expenditures. Capital expenditures in the first nine months of 2018 increased $339 million compared to 2017 due to an increase in the Company's capital program for 2018. This increase was primarily in Montney ($221 million) and Eagle Ford ($70 million).

Divestitures in the first nine months of 2018 were $89 million, which primarily included the sale of the Pipestone midstream assets in Alberta. Divestitures in the first nine months of 2017 were $710 million, which primarily included the sale of the Piceance natural gas assets in northwestern Colorado and the sale of the Tuscaloosa Marine Shale assets in Mississippi and Louisiana. Divestitures also included the sale of certain properties that did not complement Encana's existing portfolio of assets.

Acquisitions in the first nine months of 2018 and 2017 were $17 million and $50 million, respectively, which primarily included purchases with oil and liquids rich potential.

Capital expenditures and acquisition and divestiture activity are summarized in Notes 3 and 8 to the Consolidated Financial Statements included in Part I, Item 1 of this Quarterly Report on Form 10-Q.

Financing Activities

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

Encana's long-term debt, including the current portion of $500 million which is due May 2019, totaled $4,198 million at September 30, 2018 and $4,197 million at December 31, 2017. There was no current portion of long-term debt outstanding at December 31, 2017. As at September 30, 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 September 30, 2018, Encana had no outstanding balance under the Credit Facilities and $144 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 September 30, 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.

Dividends

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

	Three months ended September 30,		Nine months ended September 30,	
($ millions, except as indicated)	**2018**	2017	**2018**	2017
Dividend Payments	**$ 14**	$ 15	**$ 43**	$ 44
Dividend Payments ($/share)	**$ 0.015**	$ 0.015	**$ 0.045**	$ 0.045

On October 31, 2018, the Board of Directors declared a dividend of $0.015 per common share payable on December 31, 2018 to common shareholders of record as of December 14, 2018.

Normal Course Issuer Bid

On February 26, 2018, Encana received approval from the TSX to commence a NCIB that enables 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. The number of shares authorized for purchase represents approximately 3.6 percent of Encana's issued and outstanding common shares as at February 20, 2018. The Company has authorization from its Board to spend up to $400 million on the NCIB. For the third quarter and first nine months of 2018, the Company used cash on hand to purchase approximately 3.9 million and 20.7 million common shares, respectively, for total consideration of approximately $50 million and $250 million, respectively.

For additional information on NCIB, refer to Note 13 to the Consolidated Financial Statements included in Part I, Item 1 of this Quarterly Report on Form 10-Q.

Off-Balance Sheet Arrangements

For information on off-balance sheet arrangements and transactions, refer to the Off-Balance Sheet Arrangements section of the MD&A included in Item 7 of the 2017 Annual Report on Form 10-K.

Commitments and Contingencies

For information on commitments and contingencies, refer to Note 21 to the Consolidated Financial Statements included in Part I, Item 1 of this Quarterly Report on Form 10-Q.

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.

	Three months ended September 30,		Nine months ended September 30,	
($ millions, except as indicated)	**2018**	2017	**2018**	2017
Cash From (Used in) Operating Activities	**$ 885**	$ 357	**$ 1,741**	$ 681
(Add back) deduct:				
Net change in other assets and liabilities	**(17)**	(11)	**(33)**	(27)
Net change in non-cash working capital	**313**	98	**199**	(191)
Current tax on sale of assets	**-**	-	**-**	-
Non-GAAP Cash Flow	**$ 589**	$ 270	**$ 1,575**	$ 899
Production Volumes (MMBOE)	**34.8**	26.1	**94.7**	83.5
Non-GAAP Cash Flow Margin ($/BOE) (1)	**$ 16.93**	$ 10.34	**$ 16.63**	$ 10.77

(1) Non-GAAP Cash Flow Margin was previously presented as Corporate Margin.

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)	September 30, 2018	December 31, 2017
Long-Term Debt, including current portion	**$ 4,198**	$ 4,197
Total Shareholders' Equity	**6,494**	6,728
Equity Adjustment for Impairments at December 31, 2011	**7,746**	7,746
Adjusted Capitalization	**$ 18,438**	$ 18,671
Debt to Adjusted Capitalization	**23%**	22%

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, the Company's ability to service its debt and other financial obligations, and as a measure considered comparable to other companies in the industry. 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)	September 30, 2018	December 31, 2017
Long-Term Debt, including current portion	**$ 4,198**	$ 4,197
Less:		
Cash and cash equivalents	**615**	719
Net Debt	**3,583**	3,478
Net Earnings (Loss)	**(190)**	827
Add back (deduct):		
Depreciation, depletion and amortization	**1,167**	833
Impairments	**-**	-
Accretion of asset retirement obligation	**31**	37
Interest	**360**	363
Unrealized (gains) losses on risk management	**376**	(442)
Foreign exchange (gain) loss, net	**108**	(279)
(Gain) loss on divestitures, net	**(3)**	(404)
Other (gains) losses, net	**6**	(42)
Income tax expense (recovery)	**321**	603
Adjusted EBITDA (trailing 12-month)	**$ 2,176**	$ 1,496
Net Debt to Adjusted EBITDA (times)	**1.6**	2.3

Item 3: Quantitative and Qualitative Disclosures About Market Risk

The primary objective of the following information is to provide forward-looking quantitative and qualitative information about Encana's potential exposure to market risks. The term "market risk" refers to the Company's risk of loss arising from adverse changes in oil, NGL and natural gas prices, foreign currency exchange rates and interest rates. The following disclosures are not meant to be precise indicators of expected future losses but rather indicators of reasonably possible losses. The forward-looking information provides indicators of how the Company views and manages ongoing market risk exposures. The Company's policy is to not use derivative financial instruments for speculative purposes.

COMMODITY PRICE RISK

Commodity price risk arises from the effect fluctuations in future commodity prices, including oil, NGLs and natural gas, may have on future revenues, expenses and cash flows. Realized pricing is primarily driven by the prevailing worldwide price for crude oil and spot market prices applicable to the Company's natural gas production. Pricing for oil and natural gas production has been volatile and unpredictable as discussed in Item 1A. "Risk Factors" of the 2017 Annual Report on Form 10-K. To partially mitigate exposure to commodity price risk, the Company may enter into various derivative financial instruments including futures, forwards, swaps, options and costless collars. The use of these derivative instruments is governed under formal policies and is subject to limits established by the Board of Directors and may vary from time to time. Both exchange traded and over-the-counter traded derivative instruments may be subject to margin-deposit requirements, and the Company may be required from time to time to deposit cash or provide letters of credit with exchange brokers or counterparties to satisfy these margin requirements. For additional information relating to the Company's derivative and financial instruments, see Note 19 under Part I, Item 1 of this Quarterly Report on Form 10-Q.

The table below summarizes the sensitivity of the fair value of the Company's risk management positions to fluctuations in commodity prices, with all other variables held constant. The Company has used a 10 percent variability to assess the potential impact of commodity price changes. Fluctuations in commodity prices could have resulted in unrealized gains (losses) impacting pre-tax net earnings as follows:

	September 30, 2018	
(US$ millions)	10% Price Increase	10% Price Decrease
Crude oil price	$ (307)	$ 286
NGL price	(20)	20
Natural gas price	(47)	41

FOREIGN EXCHANGE RISK

Foreign exchange risk arises from changes in foreign exchange rates that may affect the fair value or future cash flows of the Company's financial assets or liabilities. As Encana operates in Canada and the United States, fluctuations in the exchange rate between the U.S. and Canadian dollars can have a significant effect on the Company's reported results. Although Encana's financial results are consolidated in Canadian dollars, the Company reports its results in U.S. dollars as most of its revenues are closely tied to the U.S. dollar and to facilitate a more direct comparison to other North American oil and gas companies.

The table below summarizes selected foreign exchange impacts on Encana's financial results when compared to the same periods in 2017.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	$ millions	$/BOE	$ millions	$/BOE
Increase (Decrease) in:				
Capital Investment	$ (6)		$ 2	
Transportation and Processing Expense (1)	(6)	$ (0.17)	6	$ 0.06
Operating Expense (1)	(1)	(0.04)	1	0.01
Administrative Expense	(3)	(0.07)	-	-
Depreciation, Depletion and Amortization (1)	(2)	(0.06)	3	0.03

(1) Reflects upstream operations.

Foreign exchange gains and losses also arise when monetary assets and monetary liabilities denominated in foreign currencies are translated and settled, and primarily include:

- U.S. dollar denominated financing debt issued from Canada
- U.S. dollar denominated risk management assets and liabilities held in Canada
- U.S. dollar denominated cash and short-term investments held in Canada
- Foreign denominated intercompany loans

To partially mitigate the effect of foreign exchange fluctuations on future commodity revenues and expenses, the Company may enter into foreign currency derivative contracts. As at September 30, 2018, Encana has entered into $179 million notional U.S. dollar denominated currency swaps at an average exchange rate of US$0.7606 to C$1, which mature monthly through the remainder of 2018 and $350 million notional U.S. dollar denominated currency swaps at an average exchange rate of US$0.7579 to C$1, which mature monthly throughout 2019.

As at September 30, 2018, Encana had $4.2 billion in U.S. dollar long-term debt and $259 million in U.S. dollar capital leases issued from Canada that were subject to foreign exchange exposure.

The table below summarizes the sensitivity to foreign exchange rate fluctuations, with all other variables held constant. The Company has used a 10 percent variability to assess the potential impact from Canadian to U.S. foreign currency exchange rate changes. Fluctuations in foreign currency exchange rates could have resulted in unrealized gains (losses) impacting pre-tax net earnings as follows:

	September 30, 2018	
(US$ millions)	10% Rate Increase	10% Rate Decrease
Foreign currency exchange	$ (106)	$ 129

INTEREST RATE RISK

Interest rate risk arises from changes in market interest rates that may affect the fair value or future cash flows from the Company's financial assets or liabilities. The Company may partially mitigate its exposure to interest rate changes by holding a mix of both fixed and floating rate debt and may also enter into interest rate derivatives to partially mitigate effects of fluctuations in market interest rates.

As at September 30, 2018, the Company had no floating rate debt and there were no interest rate derivatives outstanding.

Item 4: Controls and Procedures

DISCLOSURE CONTROLS AND PROCEDURES

Encana's Chief Executive Officer and Chief Financial Officer performed an evaluation of the Company's disclosure controls and procedures as defined in Rules 13a-15(e) and 15d-15(e) of the Securities Exchange Act of 1934, as amended ("Exchange Act"). The Company's disclosure controls and procedures are designed to ensure that information required to be disclosed by the Company in reports it files or submits under the Exchange Act is recorded, processed, summarized, and reported within the time periods specified in the rules and forms of the SEC, and to ensure that the information required to be disclosed by the Company in reports that it files or submits under the Exchange Act, is accumulated and communicated to the Company's management, including the principal executive officer and principal financial officer, as appropriate, to allow timely decisions regarding required disclosure. Based on this evaluation, the Chief Executive Officer and Chief Financial Officer have concluded that the Company's disclosure controls and procedures were effective as of September 30, 2018.

CHANGES IN INTERNAL CONTROL OVER FINANCIAL REPORTING

There were no changes in Encana's internal control over financial reporting during the third quarter of 2018 that materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting.

PART II

Item 1. Legal Proceedings

Please refer to Item 3 of the 2017 Annual Report on Form 10-K and Note 21 of Encana's Condensed Consolidated Financial Statements under Part I, Item 1 of this Quarterly Report on Form 10-Q.

Item 1A. Risk Factors

In addition to the other information set forth in this Quarterly Report on Form 10-Q, the reader should carefully consider the factors discussed in Item 1A. Risk Factors of the 2017 Annual Report on Form 10-K. These risks, which could materially affect our business, financial condition or future results, are not the only risks we face. Additional risks and uncertainties not currently known to us or that we currently deem to be immaterial may also adversely affect our business, financial condition and/or operating results.

In addition to the risk factors previously disclosed in the 2017 Annual Report on Form 10-K, the following are risks related to our pending acquisition of Newfield:

The transactions contemplated by the merger agreement are subject to conditions, including certain conditions that may not be satisfied, or completed on a timely basis, if at all. Failure to complete the transactions contemplated by the merger agreement, including the merger, could have material and adverse effects on Encana.

Completion of the merger is subject to a number of conditions, including, among other things, (i) the receipt of certain approvals of Encana shareholders and Newfield stockholders, (ii) the expiration or termination of the waiting period under the Hart-Scott-Rodino Antitrust Improvements Act of 1976, as amended, (iii) the effectiveness of the registration statement on Form S-4 that Encana is obligated to file with the SEC in connection with the issuance of Encana common shares in the merger, (iv) the authorization for listing of the Encana common shares to be issued in the merger on the NYSE and the TSX, (v) the accuracy of each party's representations and warranties (subject to certain materiality qualifiers) and compliance by each party with its covenants under the merger agreement in all material respects and (vi) the absence of legal restraints prohibiting or restraining the merger. Such conditions make the completion and timing of the completion of the transaction uncertain. In addition, the merger agreement contains certain termination rights for both Newfield and Encana. If the merger agreement is terminated under certain circumstances, Encana could be required to pay Newfield a termination fee of $300 million. In other circumstances, upon termination of the merger agreement, Encana could be required to pay Newfield $50 million for costs, fees and expenses incurred by Newfield. See our Current Report on Form 8-K filed with the SEC on November 2, 2018 for a more detailed discussion of the conditions to the completion of the merger and termination rights under the merger agreement.

If the transactions contemplated by the merger agreement are not completed, Encana's ongoing business may be adversely affected and, without realizing any of the benefits of having completed the transaction, Encana will be subject to a number of risks, including the following: Encana will be required to pay its costs relating to the transaction, such as legal, accounting, financial advisory and printing fees, whether or not the transaction is completed; time and resources committed by Encana's management to matters relating to the transaction could otherwise have been devoted to pursuing other beneficial opportunities; the market price of Encana common shares could be impacted to the extent that the current market price reflects a market assumption that the transaction will be completed; and if the merger agreement is terminated and the Encana Board of Directors seeks another acquisition, Encana shareholders cannot be certain that Encana will be able to find a party willing to enter into a transaction as attractive to Encana as the acquisition of Newfield.

Encana will be subject to business uncertainties while the merger is pending, which could adversely affect its business.

In connection with the pendency of the transaction, it is possible that certain persons with whom Encana has a business relationship may delay or defer certain business decisions or might decide to seek to terminate, change or renegotiate their relationships with Encana, as a result of the transaction, which could negatively affect Encana's revenues, earnings and cash flows, as well as the market price of Encana's common shares, regardless of whether the merger is completed.

Under the terms of the merger agreement, Encana is subject to certain restrictions on the conduct of its business prior to the completion of the transaction, which may adversely affect its ability to execute certain of its business strategies, including the ability in certain cases to enter into certain contracts, acquire or dispose of certain assets or incur certain indebtedness or capital expenditures. Such limitations could negatively affect Encana's business and operations prior to the completion of the transaction.

Encana shareholders will have a reduced ownership in the combined company.

In connection with the completion of the merger and the transactions contemplated by the merger agreement, based on the number of issued and outstanding shares of Newfield common stock as of October 29, 2018 and the number of outstanding Newfield equity awards currently estimated to be payable in our common shares in connection with the merger, Encana anticipates issuing up to approximately 547.5 million common shares. The actual number of Encana common shares to be issued in the merger will be determined at the completion of the merger based on the number of shares of Newfield common stock outstanding at the time of the consummation of the merger. The issuance of these new shares could have the effect of depressing the market price of Encana's common shares, through dilution of earnings per share or otherwise. Any dilution of, or delay of any accretion to, Encana's earnings per share could cause the price of its common shares to decline or increase at a reduced rate.

The transaction will also dilute the current ownership position and voting interest of Encana's shareholders. Immediately after the merger is completed, it is expected that current Encana shareholders will own approximately 63.5% and Newfield stockholders will own approximately 36.5% of the combined company's common shares outstanding, respectively. As a result, current Encana shareholders will have less influence on the policies of the combined company than they currently have.

The market price of Encana common shares could be negatively affected by risks and conditions that apply to Newfield, which may be different from the risks and conditions currently applicable to Encana.

Following the merger, Encana shareholders will own interests in a combined company operating an expanded business with more assets and a different mix of liabilities, in various jurisdictions in which Encana does not currently operate in. There is a risk that various factors, conditions and developments that would not currently affect the price of Encana common shares could, following the merger, negatively affect the price of Encana common shares. In addition, current Encana shareholders may not continue to invest in the combined company or may wish to reduce their investment in the combined company. If, following the merger, significant amounts of Encana common shares are sold, the price of Encana common shares could decline.

If the merger is completed, Encana may not achieve the intended benefits and the transaction may disrupt its current plans or operations.

There can be no assurance that Encana will be able to successfully integrate Newfield's assets or otherwise realize the expected benefits of the transaction. Difficulties in integrating Newfield into Encana may result in the combined company performing differently than expected, in operational challenges or in the failure to realize anticipated expense-related efficiencies. Potential difficulties that may be encountered in the integration process include, among other factors: the inability to successfully integrate the businesses of Newfield into Encana in a manner that permits Encana to achieve the full revenue and cost savings anticipated from the transaction; complexities associated with managing a larger, more complex, integrated business; not realizing anticipated operating synergies; integrating personnel from the two companies and the loss of key employees; potential unknown liabilities and unforeseen expenses, delays or regulatory conditions associated with and following completion of the transaction; integrating relationships with vendors and business partners; performance shortfalls at one or both of the companies as a result of the diversion of management's attention caused by completing the transaction and planning to integrate Newfield's operations into Encana; and the disruption of, or the loss of momentum in, each company's ongoing business or inconsistencies between the company's standards, controls, procedures and policies.

Completion of the merger may trigger change in control or other provisions in certain agreements to which Newfield is a party.

The completion of the transaction may trigger change in control or other provisions in certain agreements to which Newfield is a party. If Encana and Newfield are unable to negotiate waivers of those provisions, the counterparties may exercise their rights and remedies under the agreements, potentially terminating the agreements or seeking monetary damages or Encana may be required to make an offer to purchase outstanding debt securities of Newfield. Even if Encana and Newfield are able to negotiate waivers, the counterparties may require a fee for such waivers or seek to renegotiate the agreements.

Encana is expected to incur significant transaction and acquisition-related costs in connection with the merger.

Encana has incurred and is expected to continue to incur a number of non-recurring costs associated with negotiating and completing the transaction, combining the operations of the two companies and achieving desired synergies. These costs may be substantial and, in many cases, will be borne by Encana whether or not the transaction is completed. A substantial majority of non-recurring expenses will consist of transaction costs and include, among others, fees paid to financial, legal and other advisors, employee retention, severance and benefit costs and filing fees. Encana will also incur costs related to formulating and implementing integration plans, including facilities and systems consolidation costs and other employment-related costs. Encana continues to assess the magnitude of these costs, and additional unanticipated costs may be incurred in connection with the integration of the two companies' businesses. The elimination of duplicative costs, as well as the realization of other efficiencies related to the integration of the businesses, may not initially offset integration-related costs or achieve a net benefit in the near term, or at all. Any unanticipated costs and expenses could have an adverse effect on Encana's financial condition and operating results following the completion of the transaction.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds

Issuer Purchase of Equity Securities

On February 26, 2018, Encana announced it had received approval from the TSX to purchase, for cancellation, up to 35 million common shares pursuant to a NCIB over a 12-month period from February 28, 2018 to February 27, 2019.

During the three months ended September 30, 2018, the Company purchased 3.9 million common shares for total consideration of approximately $50 million at a weighted average price of $12.86. The following table presents the common shares purchased during the three months ended September 30, 2018.

Period	Total Number of Shares Purchased	Average Price Paid per Share (1)	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Number of Shares That May Yet be Purchased Under the Plans or Programs
July 1 to July 31, 2018	-	$ -	-	18,190,000
August 1 to August 31, 2018	1,875,000	13.09	1,875,000	16,315,000
September 1 to September 30, 2018	2,000,000	12.65	2,000,000	14,315,000
Total	3,875,000	$ 12.86	3,875,000	14,315,000

(1) Includes commissions.

Item 3. Defaults Upon Senior Securities

None.

Item 4. Mine Safety Disclosures

Not applicable.

Item 5. Other Information

None.

Item 6. Exhibits

Exhibit No	Description
31.1	Certification of Chief Executive Officer pursuant to Rule 13a-14(a) or 15d-14(a) of the Securities Exchange Act of 1934.
31.2	Certification of Chief Financial Officer pursuant to Rule 13a-14(a) or 15d-14(a) of the Securities Exchange Act of 1934.
32.1	Certification of Chief Executive Officer pursuant to 18 U.S.C. Section 1350.
32.2	Certification of Chief Financial Officer pursuant to 18 U.S.C. Section 1350.
101.INS	XBRL Instance Document.
101.SCH	XBRL Taxonomy Schema Document.
101.CAL	XBRL Calculation Linkbase Document.
101.DEF	XBRL Definition Linkbase Document.
101.LAB	XBRL Label Linkbase Document.
101.PRE	XBRL Presentation Linkbase Document.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

ENCANA CORPORATION

By: /s/ Sherri A. Brillon

Name: Sherri A. Brillon
Title: Executive Vice-President &
Chief Financial Officer

Dated: November 6, 2018

Encana Corporation

Interim Supplemental Information
(unaudited)

For the period ended September 30, 2018

U.S. Dollars / U.S. Protocol

Supplemental Financial Information *(unaudited)*

Financial Results

	2018				2017					
(US$ millions, unless otherwise specified)	**Year-to-date**	**Q3**	Q2	Q1	Year	Q4	Q3 Year-to-date	Q3	Q2	Q1
Net Earnings (Loss)	**39**	**39**	(151)	151	827	(229)	1,056	294	331	431
Per share - Diluted (1)	**0.04**	**0.04**	(0.16)	0.16	0.85	(0.24)	1.09	0.30	0.34	0.44
Non-GAAP Operating Earnings (Loss) (2)	**517**	**163**	198	156	422	114	308	24	180	104
Per share - Diluted (1)	**0.54**	**0.17**	0.21	0.16	0.43	0.12	0.32	0.02	0.18	0.11
Non-GAAP Cash Flow (3)	**1,575**	**589**	586	400	1,343	444	899	270	351	278
Per share - Diluted (1)	**1.64**	**0.62**	0.61	0.41	1.38	0.46	0.92	0.28	0.36	0.29
Effective Tax Rate using Canadian Statutory Rate	**27.0%**				27.0%					
Foreign Exchange Rates (US$ per C$1)										
Average	**0.777**	**0.765**	0.775	0.791	0.771	0.787	0.766	0.798	0.744	0.755
Period end	**0.773**	**0.773**	0.759	0.776	0.797	0.797	0.801	0.801	0.771	0.751
Non-GAAP Operating Earnings Summary										
Net Earnings (Loss)	**39**	**39**	(151)	151	827	(229)	1,056	294	331	431
Before-tax (Addition) Deduction:										
Unrealized gain (loss) on risk management	**(422)**	**(164)**	(326)	68	442	46	396	(76)	110	362
Non-operating foreign exchange gain (loss)	**(108)**	**24**	(32)	(100)	281	(19)	300	203	63	34
Gain (loss) on divestitures	**4**	**-**	1	3	404	(1)	405	406	-	(1)
	(526)	**(140)**	(357)	(29)	1,127	26	1,101	533	173	395
Income tax	**48**	**16**	8	24	(722)	(369)	(353)	(263)	(22)	(68)
After-tax (Addition) Deduction	**(478)**	**(124)**	(349)	(5)	405	(343)	748	270	151	327
Non-GAAP Operating Earnings (Loss) (2)	**517**	**163**	198	156	422	114	308	24	180	104
Non-GAAP Cash Flow Summary										
Cash From (Used in) Operating Activities	**1,741**	**885**	475	381	1,050	369	681	357	218	106
(Add back) Deduct:										
Net change in other assets and liabilities	**(33)**	**(17)**	(5)	(11)	(40)	(13)	(27)	(11)	(4)	(12)
Net change in non-cash working capital	**199**	**313**	(106)	(8)	(253)	(62)	(191)	98	(129)	(160)
Current tax on sale of assets	**-**	**-**	-	-	-	-	-	-	-	-
Non-GAAP Cash Flow (3)	**1,575**	**589**	586	400	1,343	444	899	270	351	278
Non-GAAP Cash Flow Margin ($/BOE) (4)	**16.63**	**16.93**	19.09	13.70	11.75	14.40	10.77	10.34	12.19	9.72

(1) Net earnings (loss), non-GAAP operating earnings (loss) and non-GAAP cash flow per common share are calculated using the weighted average number of Encana common shares outstanding as follows:

	2018				2017					
(millions)	**Year-to-date**	**Q3**	Q2	Q1	Year	Q4	Q3 Year-to-date	Q3	Q2	Q1
Weighted Average Common Shares Outstanding										
Basic	**962.2**	**955.1**	960.0	971.5	973.1	973.1	973.1	973.1	973.0	973.0
Diluted	**962.2**	**955.1**	960.0	971.5	973.1	973.1	973.1	973.1	973.0	973.0

(2) Non-GAAP Operating Earnings (Loss) is a non-GAAP measure defined as net earnings (loss) excluding non-recurring or non-cash items that Management believes reduces the comparability of the Company's financial performance between periods. These items may include, but are not limited to, unrealized gains/losses on risk management, impairments, restructuring charges, non-operating foreign exchange gains/losses, gains/losses on divestitures and gains on debt retirement. Income taxes may include valuation allowances and the provision related to the pre-tax items listed, as well as income taxes related to divestitures and U.S. tax reform, and adjustments to normalize the effect of income taxes calculated using the estimated annual effective income tax rate.

(3) 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.

(4) Non-GAAP Cash Flow Margin is a non-GAAP measure calculated as Non-GAAP Cash Flow per BOE of production.

Financial Metrics

	2018	2017
	Year-to-date	Year
Debt to Adjusted Capitalization (1)	**23%**	22%
Net Debt to Adjusted EBITDA (1)	**1.6x**	2.3x

(1) These financial metrics are non-GAAP measures monitored by Management as indicators of the Company's overall financial strength. These non-GAAP measures are defined and calculated in the Non-GAAP Definitions and Reconciliations document located on the Company's website.

Supplemental Operating Information *(unaudited)*

Production Volumes by Product

	2018				2017					
(average)	**Year-to-date**	**Q3**	Q2	Q1	Year	Q4	Q3 Year-to-date	Q3	Q2	Q1
Oil (Mbbls/d)	**87.7**	**95.5**	84.6	83.0	76.3	85.0	73.4	75.2	77.4	67.4
NGLs - Plant Condensate (Mbbls/d)	**35.0**	**41.0**	33.7	30.2	26.3	33.7	23.8	27.9	22.8	20.5
NGLs - Other (Mbbls/d)	**37.2**	**42.2**	37.0	32.0	26.5	33.9	24.0	24.4	24.7	23.0
Oil & NGLs (Mbbls/d)	**159.9**	**178.7**	155.3	145.2	129.1	152.6	121.2	127.5	124.9	110.9
Natural Gas (MMcf/d)	**1,123**	**1,197**	1,095	1,075	1,104	1,096	1,108	939	1,146	1,241
Total (MBOE/d)	**347.0**	**378.2**	337.9	324.4	313.2	335.2	305.8	284.0	316.0	317.9

Production Volumes by Segment

	2018				2017					
(average)	**Year-to-date**	**Q3**	Q2	Q1	Year	Q4	Q3 Year-to-date	Q3	Q2	Q1
Oil (Mbbls/d)										
Canadian Operations	**0.4**	**0.3**	0.4	0.4	0.4	0.4	0.5	0.6	0.4	0.4
USA Operations	**87.3**	**95.2**	84.2	82.6	75.9	84.6	72.9	74.6	77.0	67.0
	87.7	**95.5**	84.6	83.0	76.3	85.0	73.4	75.2	77.4	67.4
NGLs - Plant Condensate (Mbbls/d)										
Canadian Operations	**31.2**	**36.3**	29.9	27.5	23.1	30.2	20.7	22.8	20.5	18.7
USA Operations	**3.8**	**4.7**	3.8	2.7	3.2	3.5	3.1	5.1	2.3	1.8
	35.0	**41.0**	33.7	30.2	26.3	33.7	23.8	27.9	22.8	20.5
NGLs - Other (Mbbls/d)										
Canadian Operations	**12.5**	**14.4**	12.5	10.4	6.0	9.6	4.7	4.5	4.7	5.0
USA Operations	**24.7**	**27.8**	24.5	21.6	20.5	24.3	19.3	19.9	20.0	18.0
	37.2	**42.2**	37.0	32.0	26.5	33.9	24.0	24.4	24.7	23.0
NGLs - Total (Mbbls/d)										
Canadian Operations	**43.7**	**50.7**	42.4	37.9	29.1	39.8	25.4	27.3	25.2	23.7
USA Operations	**28.5**	**32.5**	28.3	24.3	23.7	27.8	22.4	25.0	22.3	19.8
	72.2	**83.2**	70.7	62.2	52.8	67.6	47.8	52.3	47.5	43.5
Oil & NGLs (Mbbls/d)										
Canadian Operations	**44.1**	**51.0**	42.8	38.3	29.5	40.2	25.9	27.9	25.6	24.1
USA Operations	**115.8**	**127.7**	112.5	106.9	99.6	112.4	95.3	99.6	99.3	86.8
	159.9	**178.7**	155.3	145.2	129.1	152.6	121.2	127.5	124.9	110.9
Natural Gas (MMcf/d)										
Canadian Operations	**975**	**1,038**	949	936	838	946	802	736	785	885
USA Operations	**148**	**159**	146	139	266	150	306	203	361	356
	1,123	**1,197**	1,095	1,075	1,104	1,096	1,108	939	1,146	1,241
Total (MBOE/d)										
Canadian Operations	**206.5**	**224.1**	200.9	194.3	169.1	197.7	159.5	150.4	156.6	171.7
USA Operations	**140.5**	**154.1**	137.0	130.1	144.1	137.5	146.3	133.6	159.4	146.2
	347.0	**378.2**	337.9	324.4	313.2	335.2	305.8	284.0	316.0	317.9

Oil & NGLs Production Volumes

	2018					2017						
(average Mbbls/d)	**% of Total**	**Year-to-date**	**Q3**	Q2	Q1	% of Total	Year	Q4	Q3 Year-to-date	Q3	Q2	Q1
Oil	**55**	**87.7**	**95.5**	84.6	83.0	59	76.3	85.0	73.4	75.2	77.4	67.4
NGLs - Plant Condensate	**22**	**35.0**	**41.0**	33.7	30.2	20	26.3	33.7	23.8	27.9	22.8	20.5
Oil & Plant Condensate	**77**	**122.7**	**136.5**	118.3	113.2	79	102.6	118.7	97.2	103.1	100.2	87.9
Butane	**7**	**11.2**	**13.1**	11.1	9.3	6	7.3	9.6	6.6	7.0	6.7	6.2
Propane	**9**	**15.3**	**17.6**	15.2	12.9	8	10.5	13.8	9.4	9.3	9.7	9.1
Ethane	**7**	**10.7**	**11.5**	10.7	9.8	7	8.7	10.5	8.0	8.1	8.3	7.7
NGLs - Other	**23**	**37.2**	**42.2**	37.0	32.0	21	26.5	33.9	24.0	24.4	24.7	23.0
Oil & NGLs	**100**	**159.9**	**178.7**	155.3	145.2	100	129.1	152.6	121.2	127.5	124.9	110.9

Supplemental Financial & Operating Information *(unaudited)*

Results of Operations

Revenues and Realized Gains (Losses) on Risk Management

	2018				2017					
(US$ millions)	Year-to-date	Q3	Q2	Q1	Year	Q4	Q3 Year-to-date	Q3	Q2	Q1
Canadian Operations										
Revenues, excluding Realized Gains (Losses) on Risk Management (1)										
Oil	6	1	2	3	7	2	5	2	1	2
NGLs (2)	649	257	213	179	481	184	297	106	97	94
Natural Gas	556	188	159	209	662	177	485	118	166	201
	1,211	446	374	391	1,150	363	787	226	264	297
Realized Gains (Losses) on Risk Management										
Oil	-	-	-	-	-	-	-	-	-	-
NGLs (2)	(102)	(44)	(37)	(21)	(4)	(8)	4	4	1	(1)
Natural Gas	195	52	110	33	26	24	2	21	1	(20)
	93	8	73	12	22	16	6	25	2	(21)
USA Operations										
Revenues, excluding Realized Gains (Losses) on Risk Management (1)										
Oil	1,566	586	509	471	1,360	423	937	315	324	298
NGLs (2)	219	97	70	52	193	65	128	50	38	40
Natural Gas	91	31	28	32	296	36	260	55	102	103
	1,876	714	607	555	1,849	524	1,325	420	464	441
Realized Gains (Losses) on Risk Management										
Oil	(208)	(87)	(65)	(56)	18	(12)	30	14	16	-
NGLs (2)	(3)	(3)	-	-	(1)	(2)	1	-	1	-
Natural Gas	21	4	6	11	(6)	-	(6)	-	(1)	(5)
	(190)	(86)	(59)	(45)	11	(14)	25	14	16	(5)

(1) Excludes other revenues with no associated production volumes, but includes intercompany marketing fees transacted between the Company's operating segments.

(2) Includes plant condensate.

Per-unit Results, Excluding the Impact of Realized Gains (Losses) on Risk Management (1)

	2018				2017					
(US$/BOE)	Year-to-date	Q3	Q2	Q1	Year	Q4	Q3 Year-to-date	Q3	Q2	Q1
Total Canadian Operations Netback										
Price	21.46	21.62	20.50	22.29	18.61	19.91	18.06	16.29	18.52	19.23
Production, mineral and other taxes	0.22	0.20	0.21	0.23	0.33	0.23	0.37	0.42	0.39	0.30
Transportation and processing	10.78	10.26	11.29	10.87	9.35	9.58	9.26	10.00	9.30	8.56
Operating	1.70	1.61	1.89	1.59	1.92	1.80	1.97	2.50	1.52	1.91
Netback	8.76	9.55	7.11	9.60	7.01	8.30	6.46	3.37	7.31	8.46
Total USA Operations Netback										
Price	48.90	50.30	48.72	47.39	35.16	41.52	33.15	34.13	31.92	33.59
Production, mineral and other taxes	2.53	2.91	2.48	2.12	1.74	2.22	1.59	1.69	1.29	1.84
Transportation and processing	2.39	2.38	2.51	2.26	3.12	1.82	3.53	2.55	3.54	4.44
Operating	6.16	5.56	6.75	6.28	6.18	6.19	6.17	6.57	5.60	6.43
Netback	37.82	39.45	36.98	36.73	24.12	31.29	21.86	23.32	21.49	20.88
Total Operations Netback										
Price	32.57	33.30	31.93	32.35	26.22	28.78	25.28	24.67	25.29	25.82
Production, mineral and other taxes	1.15	1.31	1.13	0.99	0.98	1.04	0.95	1.01	0.85	1.01
Transportation and processing	7.39	7.05	7.73	7.42	6.49	6.39	6.52	6.50	6.39	6.67
Operating	3.51	3.22	3.86	3.47	3.88	3.60	3.98	4.41	3.58	3.99
Netback	20.52	21.72	19.21	20.47	14.87	17.75	13.83	12.75	14.47	14.15

(1) Netback is a common metric used in the oil and gas industry to measure operating performance on a per-unit basis and is considered a non-GAAP measure. The netbacks disclosed above do not meet the requirements outlined in National Instrument 51-101 and have been calculated on a BOE basis using upstream product revenues, excluding the impact of realized gains and losses on risk management, less costs associated with delivering the product to market, including production, mineral and other taxes, transportation and processing expense and operating expense. For additional information regarding non-GAAP measures, including Netback reconciliations, see the Company's website.

Other Per-unit Results

	2018				2017					
(US$/BOE)	Year-to-date	Q3	Q2	Q1	Year	Q4	Q3 Year-to-date	Q3	Q2	Q1
Upstream Operating Expense	3.51	3.22	3.86	3.47	3.88	3.60	3.98	4.41	3.58	3.99
Upstream Operating Expense, Excluding Long-Term Incentive Costs	3.35	3.07	3.40	3.60	3.69	3.26	3.85	3.96	3.76	3.82
Administrative Expense	1.98	1.64	3.20	1.08	2.22	2.77	2.02	3.31	0.82	2.04
Administrative Expense, Excluding Long-Term Incentive Costs	1.34	1.17	1.36	1.49	1.55	1.48	1.58	1.63	1.61	1.50

Supplemental Oil and Gas Operating Statistics *(unaudited)*

Operating Statistics

Per-unit Prices, Excluding the Impact of Realized Gains (Losses) on Risk Management

	2018				2017					
(US$)	Year-to-date	Q3	Q2	Q1	Year	Q4	Q3 Year-to-date	Q3	Q2	Q1
Oil Price ($/bbl)										
Canadian Operations	57.83	60.32	58.13	55.47	42.33	61.46	37.25	31.66	40.23	43.29
USA Operations	65.66	66.84	66.57	63.33	49.14	54.44	47.07	45.78	46.14	49.65
Total Operations	65.62	66.82	66.52	63.29	49.10	54.47	47.01	45.66	46.11	49.61
NGLs - Plant Condensate Price ($/bbl)										
Canadian Operations	64.61	64.82	67.55	61.10	50.57	56.31	47.74	46.41	46.94	50.29
USA Operations	55.12	55.23	57.20	51.94	40.64	45.07	38.95	36.63	41.07	42.87
Total Operations	63.60	63.73	66.38	60.28	49.35	55.14	46.59	44.61	46.34	49.63
NGLs - Other Price ($/bbl)										
Canadian Operations	28.87	30.25	26.27	30.08	25.19	30.63	21.47	22.68	19.10	22.62
USA Operations	24.08	28.27	22.37	20.53	19.42	22.51	18.11	18.37	16.06	20.11
Total Operations	25.69	28.95	23.69	23.64	20.72	24.82	18.77	19.16	16.65	20.66
NGLs - Total Price ($/bbl)										
Canadian Operations	54.41	54.99	55.35	52.55	45.35	50.11	42.84	42.52	41.73	44.40
USA Operations	28.16	32.15	27.08	24.01	22.30	25.38	21.01	22.13	18.68	22.22
Total Operations	44.07	46.07	44.01	41.40	34.98	39.96	32.61	32.75	30.93	34.31
Oil & NGLs Price ($/bbl)										
Canadian Operations	54.44	55.03	55.38	52.58	45.30	50.21	42.74	42.28	41.71	44.38
USA Operations	56.45	58.01	56.61	54.39	42.74	47.26	40.95	39.83	40.00	43.36
Total Operations	55.90	57.16	56.27	53.91	43.33	48.04	41.33	40.37	40.35	43.59
Natural Gas Price ($/Mcf)										
Canadian Operations	2.09	1.96	1.84	2.48	2.16	2.03	2.21	1.73	2.33	2.52
USA Operations	2.25	2.19	2.07	2.52	3.03	2.63	3.10	2.90	3.09	3.23
Total Operations	2.11	1.99	1.87	2.48	2.37	2.11	2.46	1.98	2.57	2.72
Total Price ($/BOE)										
Canadian Operations	21.46	21.62	20.50	22.29	18.61	19.91	18.06	16.29	18.52	19.23
USA Operations	48.90	50.30	48.72	47.39	35.16	41.52	33.15	34.13	31.92	33.59
Total Operations	32.57	33.30	31.93	32.35	26.22	28.78	25.28	24.67	25.29	25.82

Per-unit Impact of Realized Gains (Losses) on Risk Management

	2018				2017					
(US$)	Year-to-date	Q3	Q2	Q1	Year	Q4	Q3 Year-to-date	Q3	Q2	Q1
Oil ($/bbl)										
Canadian Operations	-	-	-	-	0.25	-	0.32	-	1.07	0.08
USA Operations	(8.72)	(9.80)	(8.56)	(7.59)	0.66	(1.53)	1.52	2.14	2.17	0.05
Total Operations	(8.68)	(9.77)	(8.52)	(7.55)	0.66	(1.53)	1.51	2.12	2.16	0.05
NGLs - Plant Condensate ($/bbl)										
Canadian Operations	(11.55)	(12.23)	(13.43)	(8.55)	(0.49)	(2.78)	0.63	1.50	1.10	(0.98)
USA Operations	-	-	-	-	-	-	-	-	-	-
Total Operations	(10.31)	(10.84)	(11.90)	(7.79)	(0.43)	(2.49)	0.55	1.23	0.99	(0.89)
NGLs - Other ($/bbl)										
Canadian Operations	(1.10)	(2.83)	-	-	-	-	-	-	-	-
USA Operations	(0.39)	(1.14)	0.12	-	(0.12)	(0.74)	0.14	(0.20)	0.62	-
Total Operations	(0.63)	(1.72)	0.08	-	(0.09)	(0.53)	0.11	(0.16)	0.50	-
NGLs - Total ($/bbl)										
Canadian Operations	(8.56)	(9.56)	(9.46)	(6.19)	(0.39)	(2.11)	0.51	1.26	0.89	(0.77)
USA Operations	(0.34)	(0.98)	0.10	-	(0.10)	(0.64)	0.12	(0.16)	0.55	-
Total Operations	(5.32)	(6.21)	(5.63)	(3.77)	(0.26)	(1.51)	0.33	0.58	0.73	(0.42)
Oil & NGLs ($/bbl)										
Canadian Operations	(8.49)	(9.50)	(9.36)	(6.12)	(0.38)	(2.09)	0.51	1.23	0.90	(0.76)
USA Operations	(6.66)	(7.56)	(6.38)	(5.86)	0.48	(1.31)	1.19	1.56	1.81	0.03
Total Operations	(7.16)	(8.11)	(7.20)	(5.93)	0.28	(1.52)	1.05	1.49	1.62	(0.14)
Natural Gas ($/Mcf)										
Canadian Operations	0.73	0.54	1.27	0.39	0.09	0.27	0.01	0.32	-	(0.24)
USA Operations	0.52	0.27	0.39	0.93	(0.06)	-	(0.07)	-	(0.03)	(0.16)
Total Operations	0.70	0.51	1.16	0.46	0.05	0.23	(0.01)	0.25	(0.01)	(0.22)
Total ($/BOE)										
Canadian Operations	1.64	0.35	4.03	0.67	0.36	0.88	0.14	1.80	0.16	(1.37)
USA Operations	(4.94)	(5.98)	(4.82)	(3.83)	0.22	(1.07)	0.62	1.16	1.07	(0.37)
Total Operations	(1.02)	(2.23)	0.44	(1.13)	0.29	0.08	0.37	1.50	0.62	(0.91)

Supplemental Oil and Gas Operating Statistics *(unaudited)*

Operating Statistics (continued)

Per-unit Results, Including the Impact of Realized Gains (Losses) on Risk Management

	2018				2017					
(US$)	**Year-to-date**	**Q3**	Q2	Q1	Year	Q4	Q3 Year-to-date	Q3	Q2	Q1
Oil Price ($/bbl)										
Canadian Operations	**57.83**	**60.32**	58.13	55.47	42.58	61.46	37.57	31.66	41.30	43.37
USA Operations	**56.94**	**57.04**	58.01	55.74	49.80	52.91	48.59	47.92	48.31	49.70
Total Operations	**56.94**	**57.05**	58.00	55.74	49.76	52.94	48.52	47.78	48.27	49.66
NGLs - Plant Condensate Price ($/bbl)										
Canadian Operations	**53.06**	**52.59**	54.12	52.55	50.08	53.53	48.37	47.91	48.04	49.31
USA Operations	**55.12**	**55.23**	57.20	51.94	40.64	45.07	38.95	36.63	41.07	42.87
Total Operations	**53.29**	**52.89**	54.48	52.49	48.92	52.65	47.14	45.84	47.33	48.74
NGLs - Other Price ($/bbl)										
Canadian Operations	**27.77**	**27.42**	26.27	30.08	25.19	30.63	21.47	22.68	19.10	22.62
USA Operations	**23.69**	**27.13**	22.49	20.53	19.30	21.77	18.25	18.17	16.68	20.11
Total Operations	**25.06**	**27.23**	23.77	23.64	20.63	24.29	18.88	19.00	17.15	20.66
NGLs - Total Price ($/bbl)										
Canadian Operations	**45.85**	**45.43**	45.89	46.36	44.96	48.00	43.35	43.78	42.62	43.63
USA Operations	**27.82**	**31.17**	27.18	24.01	22.20	24.74	21.13	21.97	19.23	22.22
Total Operations	**38.75**	**39.86**	38.38	37.63	34.72	38.45	32.94	33.33	31.66	33.89
Oil & NGLs Price ($/bbl)										
Canadian Operations	**45.95**	**45.53**	46.02	46.46	44.92	48.12	43.25	43.51	42.61	43.62
USA Operations	**49.79**	**50.45**	50.23	48.53	43.22	45.95	42.14	41.39	41.81	43.39
Total Operations	**48.74**	**49.05**	49.07	47.98	43.61	46.52	42.38	41.86	41.97	43.45
Natural Gas Price ($/Mcf)										
Canadian Operations	**2.82**	**2.50**	3.11	2.87	2.25	2.30	2.22	2.05	2.33	2.28
USA Operations	**2.77**	**2.46**	2.46	3.45	2.97	2.63	3.03	2.90	3.06	3.07
Total Operations	**2.81**	**2.50**	3.03	2.94	2.42	2.34	2.45	2.23	2.56	2.50
Total Price ($/BOE)										
Canadian Operations	**23.10**	**21.97**	24.53	22.96	18.97	20.79	18.20	18.09	18.68	17.86
USA Operations	**43.96**	**44.32**	43.90	43.56	35.38	40.45	33.77	35.29	32.99	33.22
Total Operations	**31.55**	**31.07**	32.37	31.22	26.51	28.86	25.65	26.17	25.91	24.91
Total Netback ($/BOE)										
Canadian Operations	**10.40**	**9.90**	11.14	10.27	7.37	9.18	6.60	5.17	7.47	7.09
USA Operations	**32.88**	**33.47**	32.16	32.90	24.34	30.22	22.48	24.48	22.56	20.51
Total Operations	**19.50**	**19.49**	19.65	19.34	15.16	17.83	14.20	14.25	15.09	13.24

Supplemental Oil and Gas Operating Statistics *(unaudited)*

Results by Play

	2018				2017					
(average)	**Year-to-date**	**Q3**	Q2	Q1	Year	Q4	Q3 Year-to-date	Q3	Q2	Q1
Oil Production (Mbbls/d)										
Canadian Operations										
Montney	**0.3**	**0.2**	0.3	0.3	0.2	0.2	0.2	0.2	0.2	0.2
Duvernay	**0.1**	**0.1**	0.1	0.1	0.2	0.2	0.2	0.3	0.1	0.1
Other Upstream Operations (1)	**-**	**-**	-	-	-	-	0.1	0.1	0.1	0.1
Total Canadian Operations	**0.4**	**0.3**	0.4	0.4	0.4	0.4	0.5	0.6	0.4	0.4
USA Operations										
Eagle Ford	**28.0**	**31.3**	26.8	25.8	30.8	29.8	31.2	32.8	34.3	26.4
Permian	**57.1**	**61.9**	55.2	54.2	41.4	52.2	37.7	38.6	39.0	35.6
Other Upstream Operations (1)	**2.2**	**2.0**	2.2	2.6	3.7	2.6	4.0	3.2	3.7	5.0
Total USA Operations	**87.3**	**95.2**	84.2	82.6	75.9	84.6	72.9	74.6	77.0	67.0
Total Encana	**87.7**	**95.5**	84.6	83.0	76.3	85.0	73.4	75.2	77.4	67.4
NGLs - Plant Condensate Production (Mbbls/d)										
Canadian Operations										
Montney	**25.2**	**30.5**	24.2	20.8	14.6	20.7	12.5	14.3	12.2	10.9
Duvernay	**6.1**	**5.8**	5.7	6.8	8.3	9.4	8.0	8.3	8.2	7.6
Other Upstream Operations (1)	**(0.1)**	**-**	-	(0.1)	0.2	0.1	0.2	0.2	0.1	0.2
Total Canadian Operations	**31.2**	**36.3**	29.9	27.5	23.1	30.2	20.7	22.8	20.5	18.7
USA Operations										
Eagle Ford	**1.5**	**2.0**	1.6	1.1	1.4	1.4	1.4	3.1	0.7	0.5
Permian	**2.1**	**2.5**	2.1	1.5	1.5	1.9	1.3	1.7	1.3	1.0
Other Upstream Operations (1)	**0.2**	**0.2**	0.1	0.1	0.3	0.2	0.4	0.3	0.3	0.3
Total USA Operations	**3.8**	**4.7**	3.8	2.7	3.2	3.5	3.1	5.1	2.3	1.8
Total Encana	**35.0**	**41.0**	33.7	30.2	26.3	33.7	23.8	27.9	22.8	20.5

(1) Other Upstream Operations includes production volumes from plays that are not part of the Company's current strategic focus. Canadian Other Upstream Operations primarily includes Wheatland; USA Other Upstream Operations primarily includes San Juan, Piceance and Tuscaloosa Marine Shale ("TMS"). Production volumes associated with Wheatland, Piceance and TMS were included in Other Upstream Operations until the divestitures of these assets on December 13, 2017, July 25, 2017 and April 13, 2017, respectively.

Supplemental Oil and Gas Operating Statistics *(unaudited)*

Results by Play (continued)

	2018				2017					
(average)	**Year-to-date**	**Q3**	Q2	Q1	Year	Q4	Q3 Year-to-date	Q3	Q2	Q1
NGLs - Other Production (Mbbls/d)										
Canadian Operations										
Montney	**11.4**	**13.5**	11.5	9.3	4.5	8.1	3.3	3.1	3.4	3.5
Duvernay	**1.1**	**1.0**	1.0	1.2	1.3	1.5	1.2	1.2	1.2	1.2
Other Upstream Operations (1)	**-**	**(0.1)**	-	(0.1)	0.2	-	0.2	0.2	0.1	0.3
Total Canadian Operations	**12.5**	**14.4**	12.5	10.4	6.0	9.6	4.7	4.5	4.7	5.0
USA Operations										
Eagle Ford	**6.5**	**7.4**	6.5	5.4	6.8	6.9	6.8	6.8	7.2	6.1
Permian	**17.0**	**19.2**	16.8	15.0	12.1	15.6	11.0	11.8	11.0	10.1
Other Upstream Operations (1)	**1.2**	**1.2**	1.2	1.2	1.6	1.8	1.5	1.3	1.8	1.8
Total USA Operations	**24.7**	**27.8**	24.5	21.6	20.5	24.3	19.3	19.9	20.0	18.0
Total Encana	**37.2**	**42.2**	37.0	32.0	26.5	33.9	24.0	24.4	24.7	23.0
NGLs - Total Production (Mbbls/d)										
Canadian Operations										
Montney	**36.6**	**44.0**	35.7	30.1	19.1	28.8	15.8	17.4	15.6	14.4
Duvernay	**7.2**	**6.8**	6.7	8.0	9.6	10.9	9.2	9.5	9.4	8.8
Other Upstream Operations (1)	**(0.1)**	**(0.1)**	-	(0.2)	0.4	0.1	0.4	0.4	0.2	0.5
Total Canadian Operations	**43.7**	**50.7**	42.4	37.9	29.1	39.8	25.4	27.3	25.2	23.7
USA Operations										
Eagle Ford	**8.0**	**9.4**	8.1	6.5	8.2	8.3	8.2	9.9	7.9	6.6
Permian	**19.1**	**21.7**	18.9	16.5	13.6	17.5	12.3	13.5	12.3	11.1
Other Upstream Operations (1)	**1.4**	**1.4**	1.3	1.3	1.9	2.0	1.9	1.6	2.1	2.1
Total USA Operations	**28.5**	**32.5**	28.3	24.3	23.7	27.8	22.4	25.0	22.3	19.8
Total Encana	**72.2**	**83.2**	70.7	62.2	52.8	67.6	47.8	52.3	47.5	43.5

(1) Other Upstream Operations includes production volumes from plays that are not part of the Company's current strategic focus. Canadian Other Upstream Operations primarily includes Wheatland; USA Other Upstream Operations primarily includes San Juan, Piceance and TMS. Production volumes associated with Wheatland, Piceance and TMS were included in Other Upstream Operations until the divestitures of these assets on December 13, 2017, July 25, 2017 and April 13, 2017, respectively.

Supplemental Oil and Gas Operating Statistics *(unaudited)*

Results by Play (continued)

(average)	2018 Year-to-date	2018 Q3	2018 Q2	2018 Q1	2017 Year	2017 Q4	2017 Q3 Year-to-date	2017 Q3	2017 Q2	2017 Q1
Oil & NGLs Production (Mbbls/d)										
Canadian Operations										
Montney	**36.9**	**44.2**	36.0	30.4	19.3	29.0	16.0	17.6	15.8	14.6
Duvernay	**7.3**	**6.9**	6.8	8.1	9.8	11.1	9.4	9.8	9.5	8.9
Other Upstream Operations (1)	**(0.1)**	**(0.1)**	-	(0.2)	0.4	0.1	0.5	0.5	0.3	0.6
Total Canadian Operations	**44.1**	**51.0**	42.8	38.3	29.5	40.2	25.9	27.9	25.6	24.1
USA Operations										
Eagle Ford	**36.0**	**40.7**	34.9	32.3	39.0	38.1	39.4	42.7	42.2	33.0
Permian	**76.2**	**83.6**	74.1	70.7	55.0	69.7	50.0	52.1	51.3	46.7
Other Upstream Operations (1)	**3.6**	**3.4**	3.5	3.9	5.6	4.6	5.9	4.8	5.8	7.1
Total USA Operations	**115.8**	**127.7**	112.5	106.9	99.6	112.4	95.3	99.6	99.3	86.8
Total Encana	**159.9**	**178.7**	155.3	145.2	129.1	152.6	121.2	127.5	124.9	110.9
Natural Gas Production (MMcf/d)										
Canadian Operations										
Montney	**864**	**938**	841	810	644	775	600	562	592	648
Duvernay	**56**	**54**	52	61	64	72	61	65	62	55
Other Upstream Operations (1)	**55**	**46**	56	65	130	99	141	109	131	182
Total Canadian Operations	**975**	**1,038**	949	936	838	946	802	736	785	885
USA Operations										
Eagle Ford	**50**	**56**	49	47	51	52	50	55	52	43
Permian	**84**	**90**	85	78	67	77	64	72	62	58
Other Upstream Operations (1)	**14**	**13**	12	14	148	21	192	76	247	255
Total USA Operations	**148**	**159**	146	139	266	150	306	203	361	356
Total Encana	**1,123**	**1,197**	1,095	1,075	1,104	1,096	1,108	939	1,146	1,241

(1) Other Upstream Operations includes production volumes from plays that are not part of the Company's current strategic focus. Canadian Other Upstream Operations primarily includes Wheatland and natural gas volumes in Horn River and Deep Panuke; USA Other Upstream Operations primarily includes San Juan, Piceance and oil volumes in TMS. Production volumes associated with Wheatland, Piceance and TMS were included in Other Upstream Operations until the divestitures of these assets on December 13, 2017, July 25, 2017 and April 13, 2017, respectively.

Supplemental Oil and Gas Operating Statistics *(unaudited)*

Results by Play (continued)

	2018				2017					
(average)	**Year-to-date**	**Q3**	Q2	Q1	Year	Q4	Q3 Year-to-date	Q3	Q2	Q1
Total Production (MBOE/d)										
Canadian Operations										
Montney	**180.8**	**200.6**	176.2	165.3	126.7	158.0	116.1	111.3	114.4	122.7
Duvernay	**16.6**	**15.9**	15.5	18.3	20.4	23.0	19.5	20.7	19.7	18.1
Other Upstream Operations (1)	**9.1**	**7.6**	9.2	10.7	22.0	16.7	23.9	18.4	22.5	30.9
Total Canadian Operations	**206.5**	**224.1**	200.9	194.3	169.1	197.7	159.5	150.4	156.6	171.7
USA Operations										
Eagle Ford	**44.4**	**49.9**	43.0	40.1	47.4	46.7	47.7	51.9	50.8	40.2
Permian	**90.2**	**98.5**	88.2	83.8	66.2	82.6	60.7	64.1	61.6	56.3
Other Upstream Operations (1)	**5.9**	**5.7**	5.8	6.2	30.5	8.2	37.9	17.6	47.0	49.7
Total USA Operations	**140.5**	**154.1**	137.0	130.1	144.1	137.5	146.3	133.6	159.4	146.2
Total Encana	**347.0**	**378.2**	337.9	324.4	313.2	335.2	305.8	284.0	316.0	317.9
Total Production (MBOE/d)										
Total Core Assets	**332.0**	**364.9**	322.9	307.5	260.7	310.3	244.0	248.0	246.5	237.3
% of Total Encana	**96%**	**96%**	96%	95%	83%	93%	80%	87%	78%	75%

	2018				2017					
(US$ millions)	**Year-to-date**	**Q3**	Q2	Q1	Year	Q4	Q3 Year-to-date	Q3	Q2	Q1
Capital Expenditures										
Canadian Operations										
Montney	**445**	**120**	170	155	346	122	224	101	62	61
Duvernay	**107**	**52**	42	13	78	10	68	22	20	26
Other Upstream Operations (2)	**1**	**2**	(1)	-	2	2	-	-	(1)	1
Total Canadian Operations	**553**	**174**	211	168	426	134	292	123	81	88
USA Operations										
Eagle Ford	**315**	**99**	122	94	304	59	245	56	83	106
Permian	**718**	**230**	250	238	1,001	298	703	278	228	197
Other Upstream Operations (2)	**32**	**16**	10	6	53	10	43	13	22	8
Total USA Operations	**1,065**	**345**	382	338	1,358	367	991	347	333	311
Market Optimization	**-**	**-**	-	-	1	-	1	1	-	-
Corporate & Other	**8**	**4**	2	2	11	8	3	2	1	-
Capital Expenditures	**1,626**	**523**	595	508	1,796	509	1,287	473	415	399
Net Acquisitions & (Divestitures)	**(72)**	**(9)**	(46)	(17)	(682)	(22)	(660)	(623)	(80)	43
Net Capital Investment	**1,554**	**514**	549	491	1,114	487	627	(150)	335	442

(1) Other Upstream Operations includes total production volumes from plays that are not part of the Company's current strategic focus. Canadian Other Upstream Operations primarily includes Wheatland, Horn River and Deep Panuke; USA Other Upstream Operations primarily includes San Juan, Piceance and TMS. Production volumes associated with Wheatland, Piceance and TMS were included in Other Upstream Operations until the divestitures of these assets on December 13, 2017, July 25, 2017 and April 13, 2017, respectively.

(2) Other Upstream Operations includes capital expenditures in plays that are not part of the Company's current strategic focus, as well as capital expenditures in plays where the Company is pursuing growth opportunities. Canadian Other Upstream Operations primarily includes Wheatland; USA Other Upstream Operations primarily includes San Juan, Piceance and TMS.

Supplemental Oil and Gas Operating Statistics *(unaudited)*

Results by Play (continued)

	2018				2017					
	Year-to-date	**Q3**	Q2	Q1	Year	Q4	Q3 Year-to-date	Q3	Q2	Q1
Drilling Activity (net wells drilled)										
Canadian Operations										
Montney	**108**	**27**	41	40	108	35	73	32	20	21
Duvernay	**9**	**2**	4	3	9	-	9	-	2	7
Other Upstream Operations [(1)]	**1**	**1**	-	-	-	-	-	-	-	-
Total Canadian Operations	**118**	**30**	45	43	117	35	82	32	22	28
USA Operations										
Eagle Ford	**40**	**12**	14	14	37	5	32	6	9	17
Permian	**81**	**26**	29	26	126	32	94	30	30	34
Other Upstream Operations [(1)]	**5**	**5**	-	-	5	-	5	1	2	2
Total USA Operations	**126**	**43**	43	40	168	37	131	37	41	53
Total Encana	**244**	**73**	88	83	285	72	213	69	63	81

(1) Other Upstream Operations includes net wells drilled in plays that are not part of the Company's current strategic focus, as well as net wells drilled in plays where the Company is pursuing growth opportunities. USA Other Upstream Operations primarily includes San Juan.

Encana Corporation

Further information on Encana Corporation is available on the company's website, www.encana.com, or by contacting:

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