ENCANA CORPORATION

Q2 2017
Results Conference Call

July 21, 2017

encana®

FOCUS ON QUALITY CORPORATE RETURNS

- **Business we have been building has arrived**
  - Delivering quality returns through the cycle
  - Margins expansion happening earlier than original guidance
  - Expect to be ~2X net debt / adjusted EBITDA[Ŧ] by year-end 2017
- **Productivity gains boost 2017 & five-year-plan**
  - 14% quarterly oil and condensate production growth
  - Now expect 25-30% Q4 2016 to Q4 2017 core asset production growth
  - Montney liquids mix set to double
- **Innovation continuing to drive upside**
  - Completion design innovation has boosted type curves across portfolio
  - Premium inventory growth to >11,000 locations
  - Development at scale in stacked pay contributing to a ~10% improvement in capital efficiency
  - More than offsetting cost inflation
- **Commercial mindset to grow value not just volumes**
  - Managing risk
  - Preserving optionality

[Ŧ] Non-GAAP measures defined in advisories. For additional information regarding non-GAAP measures, including reconciliations, see the Company's website.

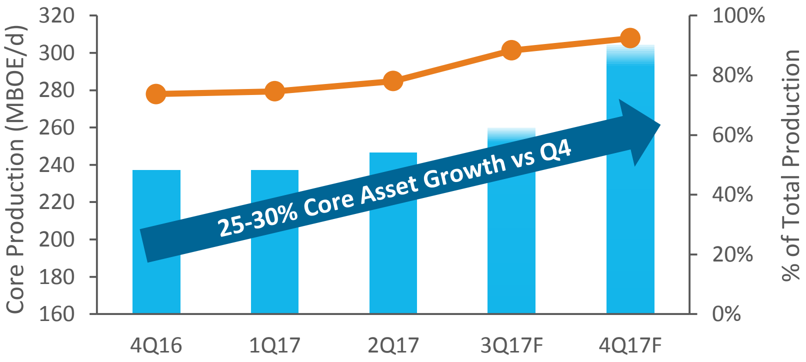
STRONGLY AHEAD IN YEAR 1 OF 5 YEAR PLAN

Core Assets Growth Ahead of Target

- Robust corporate margin[Ŧ] expansion through higher value product mix and lower costs
- Production “bounce” of core assets ahead of schedule
- 25-30% core asset growth 4Q16 to 4Q17
  - Up from original guidance of >20%
  - Core assets to make up >90% of total Q4F production
- 35-40% oil & condensate growth 4Q16 to 4Q17
- Shift to balanced commodity mix expected by Q4
- Improved capital efficiency by ~10% versus original guidance
  - Driven by both highly efficient D&C costs and higher well productivity
  - Capital program on track with stronger production results
  - Execution efficiency and supply chain more than offsetting inflation

	Q2 2017	Q1 2017
Cash Flow[Ŧ] ($MM)	351	278
Operating Margin[Ŧ], Excl. Hedge ($/BOE)	14.47	14.15
Corporate Margin[Ŧ] ($/BOE)	12.19	9.72
Capital Investment ($MM)	415	399
Total Liquids (Mbbls/d)	125	111
Liquids Mix [%]	40%	35%

Core Production Now Expected to Grow 25-30%



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UPDATED 2017 GUIDANCE

Performance Exceeding Expectations

- **Improving guidance**
  - Production guidance raised (ex. dispositions)
  - Cash cost guidance lowered
  - No change to capital guidance
- **Core asset Q4/16 to Q4/17 production now expected to grow by 25-30%**
  - Original guidance was >20%
- **Cash flowŦ and corporate marginŦ expectations ahead of plan**
  - Cash flowŦ impact of dispositions of ~$100mm annualized more than offset by production growth and cost efficiencies
  - 80-85% of 2017F liquids is oil & condensate, 15-20% NGLs

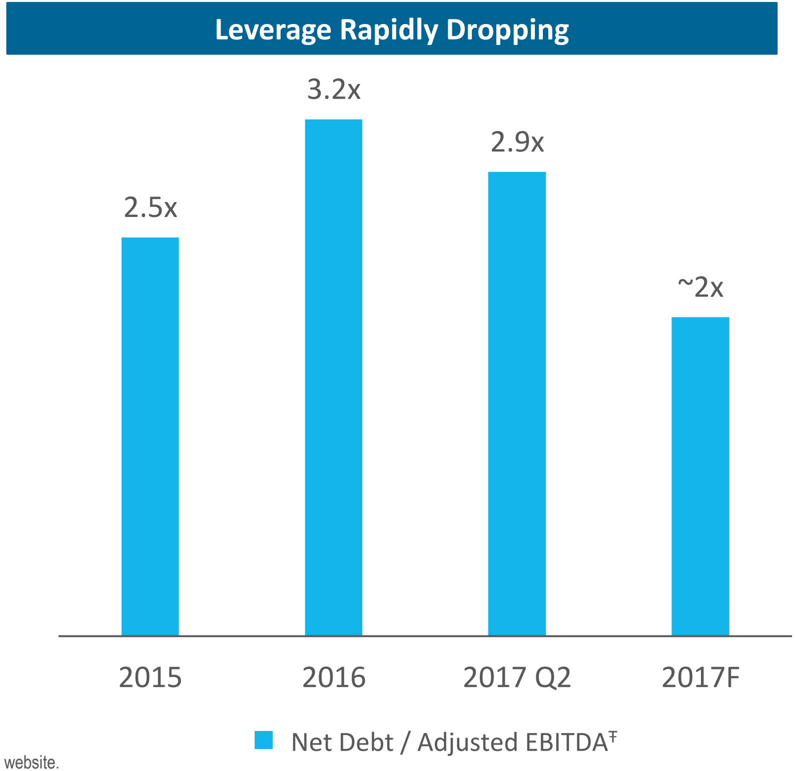
	2017 Original Guidance	Disposition Impact**	Improvements (Midpoint)	2017 July Guidance
Capital Investment ($MM)	1,600 - 1,800	-	-	1,600 - 1,800
Total Liquids (Mbbls/d)	125 – 130	(2)	4	127 – 132
Natural Gas (MMcf/d)	1,150 - 1,200	(96)	21	1,075 - 1,125
Total Production (MBOE/d)	320 – 330	(18)	8	310 – 320
Core Asset 4Q16 to 4Q17 Production Growth	>20%	-	-	25 - 30%
Transportation & Processing ($/BOE)	6.50 - 7.00	(0.20)	(0.18)	6.25 – 6.50
Operating* ($/BOE)	3.75 - 4.25	(0.05)	(0.15)	3.60 - 4.00
PMOT (% of Product Revenue)	3.75 - 4.25%	-	-	3.75 - 4.25%
Administrative Expense* ($/BOE)	1.40 - 1.60	-	-	1.40 - 1.60

*Excludes LTIs Ŧ Non-GAAP measures defined in advisories. For additional information regarding non-GAAP measures, including reconciliations, see the Company's website. **Disposition impact reflects the assumed close of Piceance disposition early in Q3 and TMS, which closed in Q2.

DISCIPLINED FINANCIAL MANAGEMENT

Balance Sheet Continues to Strengthen for Third Consecutive Year

- **Well positioned for price volatility**
  - >75% hedged through second half 2017 on both gas oil/C5+
  - Expect to have >$5 billion of liquidity at year-end
- **Expect net debt to EBITDAŦ of ~2x by Y/E 2017***
- **Total debt reduced by ~$3 billion since Y/E 2014**
- **Significant financial flexibility with no debt maturities until 2019**
- **~75% of fixed rate long-term debt not due until 2030+**
- **Investment grade credit rating**
- **$4.5B fully committed, unsecured, revolving credit facilities**



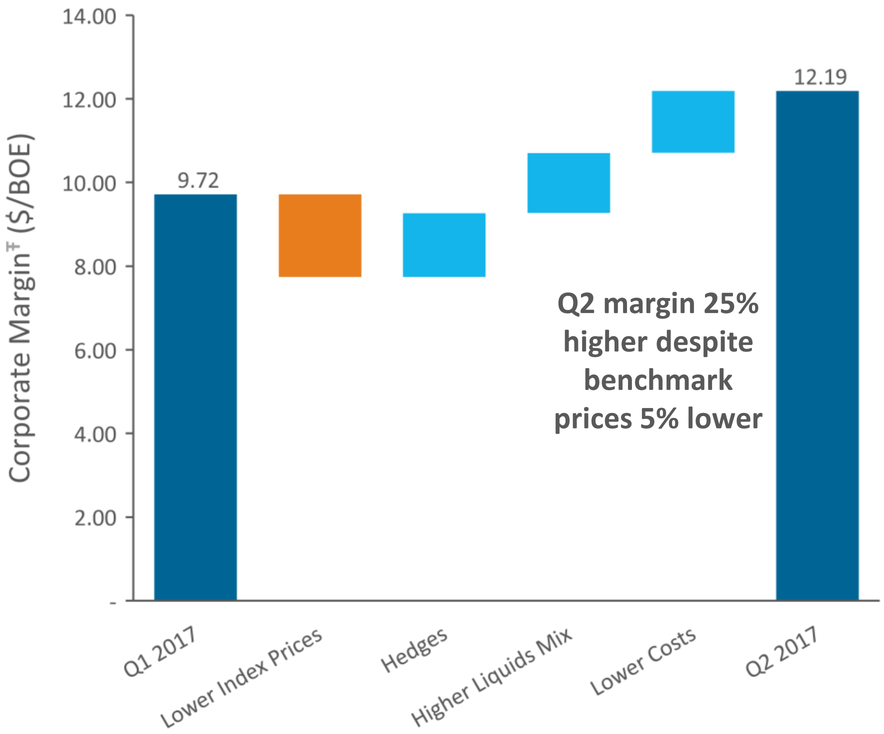
Ŧ Non-GAAP measures defined in advisories. For additional information regarding non-GAAP measures, including reconciliations, see the Company's website.
*2017 based on YTD actual commodity prices (as of June 30th) and second half 2017 forward strip prices.

EXPANDING MARGINS

Liquids Growth Driving Margin Expansion

- **Improving core asset production volumes**
  - In Q2, liquids up to 40% of total production
  - Core assets growing 25-30% Q4/16 to Q4/17
    - Previous target of >20%
  - Balanced liquids and gas production by Q4/17
    - Liquids expected to be ~45% of production by Q4 vs. 34% in Q4/16
- **Lower costs continue to support margin expansion**
  - Per unit T&P, operating expense and corporate costs down ~$1.50/BOE on combined basis

Product Mix & Efficiency Driving Corporate Margin[Ŧ] Higher



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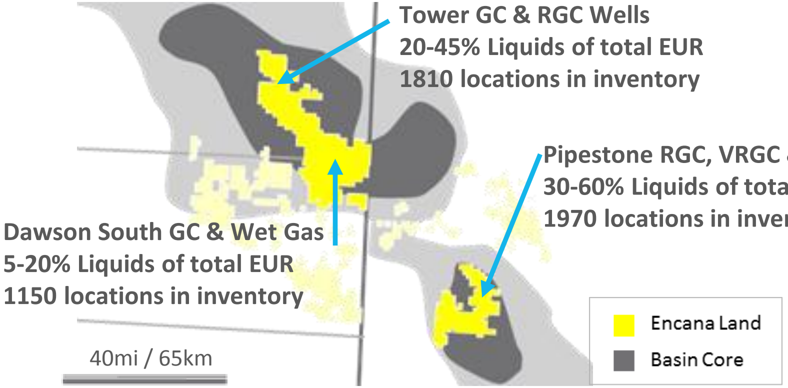
SUSTAINED MONTNEY LIQUIDS GROWTH

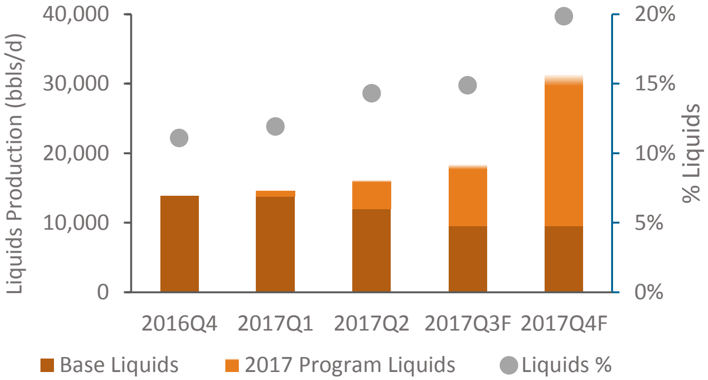
New Production Boosting Liquids Mix

- **2017 Montney program averages ~35% liquids**
  - Base Montney production averages ~10%
- **By Q4/17, expected to average ~20% liquids production**
  - Montney liquids production more than doubles from Q4/16 to Q4/17
  - Montney liquids increased from 11% in Q4/16 to 14% in Q2/17

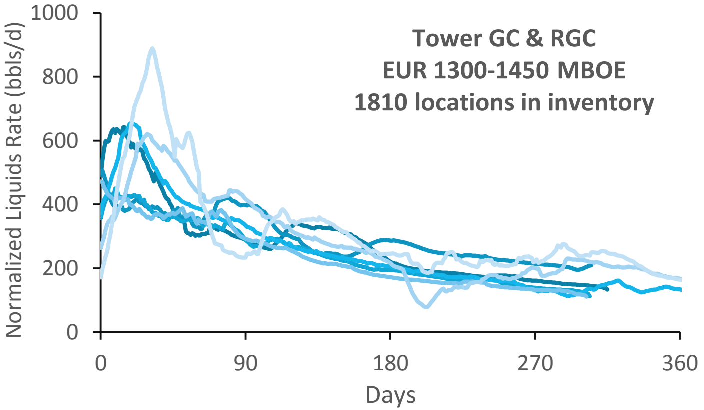
Developing Liquids-rich Acreage in the Core of the Play



Montney Liquids Growing Every Quarter



Tower Well Rates & Liquids Yields Sustained*



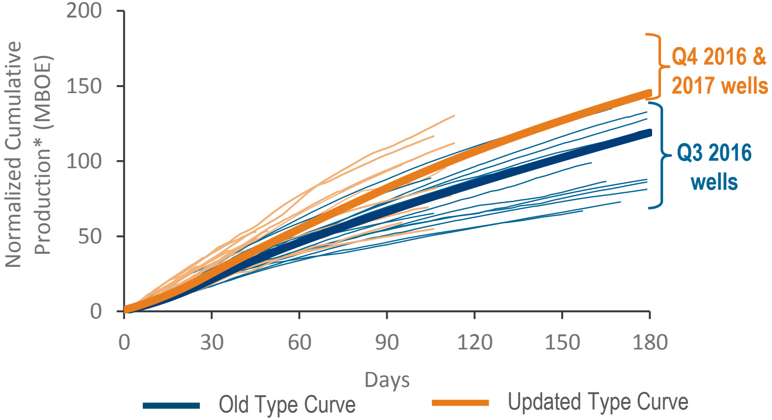
*Well results normalized to 9000' lateral length

BOOSTING PREMIUM TYPE CURVES

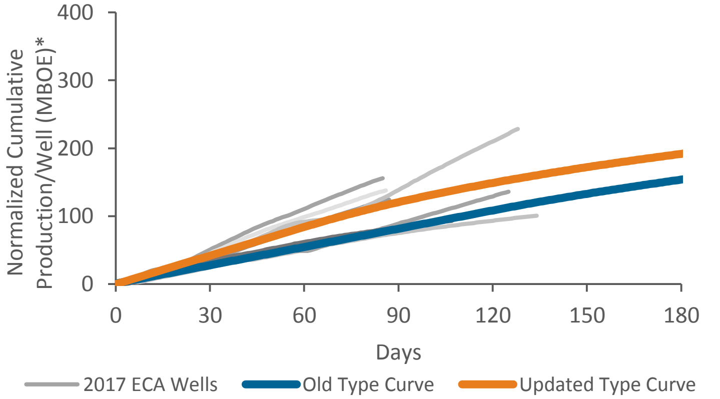
Completions Driving Productivity

- **Wells consistently outperforming type curves**
  - Cube development
  - Optimized completions
  - Improved targeting
- **Permian premium return type curves increased**
  - 20% average improvement in IP180
- **Montney premium return type curves increased**
  - 25% average improvement in IP180
- **Eagle Ford premium return type curves increased**
  - 45% average improvement in IP180 in Eagle Ford zone
  - 45% average improvement in IP30 in Austin Chalk

Permian Well Productivity Increased by 20%*



Austin Chalk Productivity Increased by 45%**



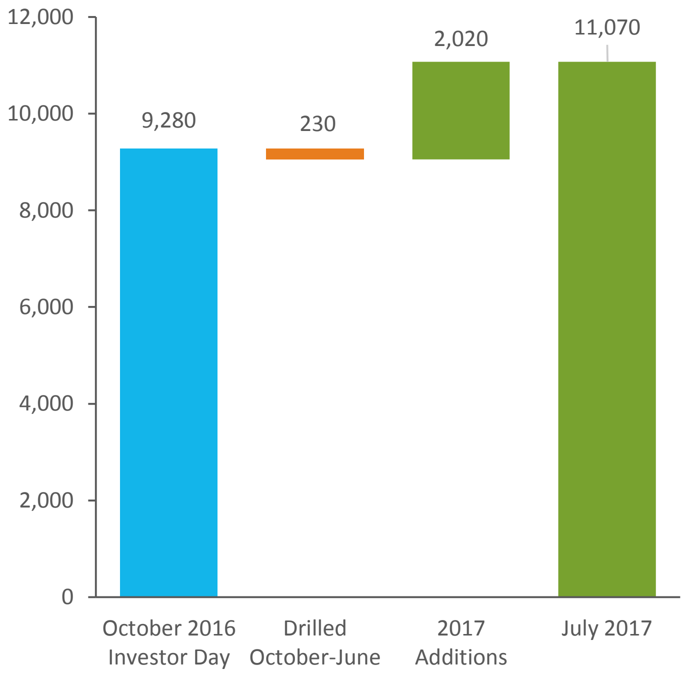
*Permian well results normalized to 7,500' lateral **Austin Chalk well results normalized to 5,000' lateral

PREMIUM RETURN INVENTORY GROWING

Deepest High Quality Inventory in Industry

- **Now >11,000 total premium return locations**
  - Includes replacement of 230 gross wells drilled since October 2016
  - YTD premium inventory increased by ~6X 2017 drilling activity
- **Driven by type curve increases across the assets plus down-spacing and coring up acreage in the Permian**

Premium Inventory Change Since October 2016

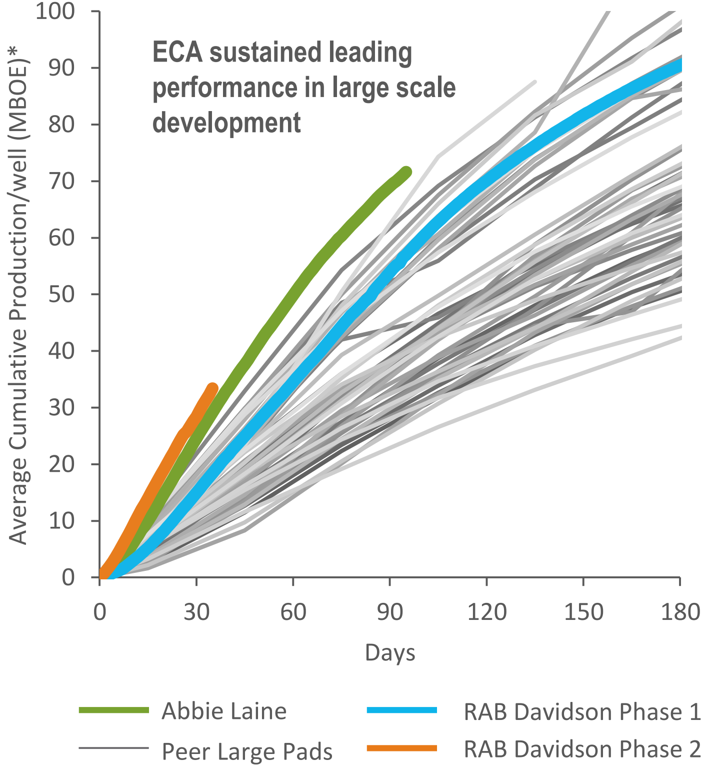


DEVELOPING THE CUBE

Permian Cube

- **Operators must be able to efficiently execute at scale to create value and returns from the play**
- **Cube development approach:**
  - Developing entire stack will be critical to creating value
  - Eliminates parent-child in-fill drilling and optimizes resource recovery – maximizing corporate returns
  - ~$1.2 MM savings/well vs. single-well development
  - 45 ECA Cube wells on production in Permian
- **Industry leading D&C costs at $5 MM/well**
- **Demonstrated sophisticated planning & logistics to execute mega-pad developments in the basin**
- **Centralized pad locations optimize infrastructure utilization and drive operating cost lower**

Large Scale Development Performance Comparison



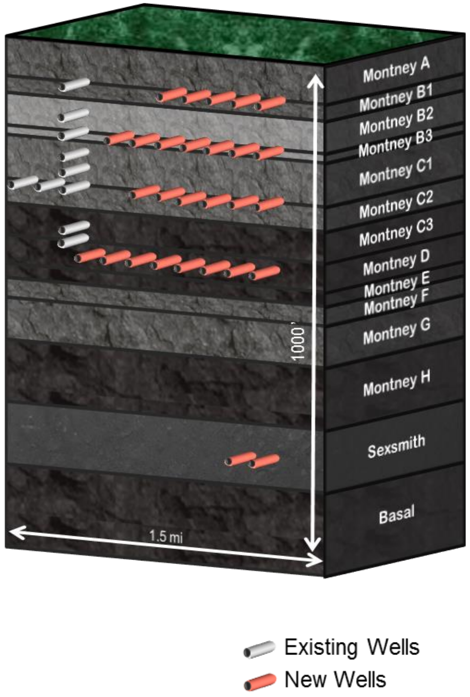
*Well results normalized to 7,500' lateral

DEVELOPING THE CUBE

Montney Cube

- **Multiple proven Montney benches on ECA lands**
- **New Dawson South 4-well pad confirming expectations**
  - Averaged >525 bbls/d liquids and >2,600 BOE/d IP30
  - Expect additional up-side with implementation of advanced completions
- **Starting to flow the Tower North cube with 28 wells in 5 benches**
- **Tower South cube currently drilling 20 wells in 4 benches**
- **2017 Montney cube developments will flow to new plants, on track for Q4 2017 start-up**
- **Montney cubes utilize multiple rigs and frac crews**
- **Pacesetter Q2 Montney cube <$3.5 MM D&C cost for 9,000' lateral**

28 Well Tower Cube Development

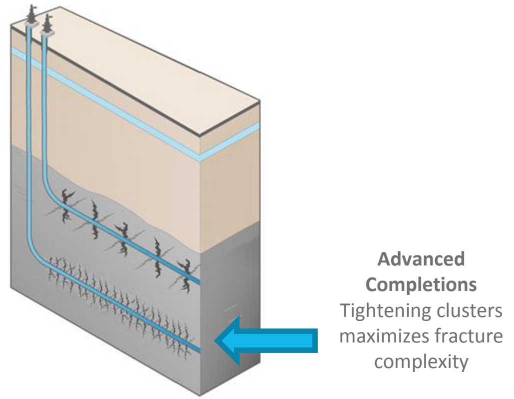


USING INNOVATION TO ADD VALUE

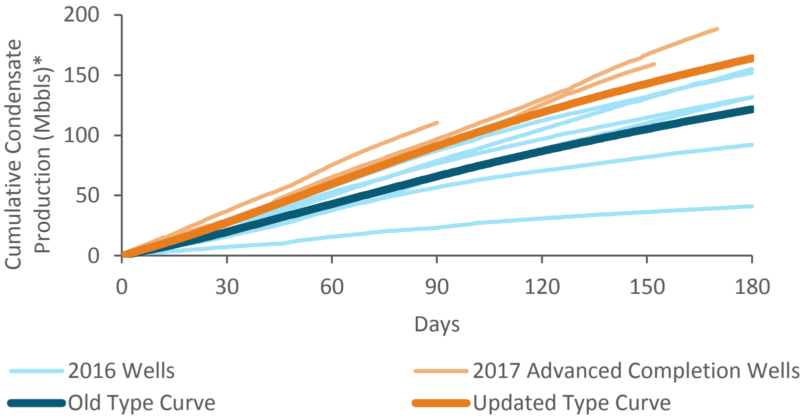
Differentiated Pace of Improvement

- **Rapid knowledge transfer across our assets**
  - Successfully implemented Advanced Completions across the core assets
  - Thin fluid, tight cluster design
  - Results expected later in 2017 in Permian and Duvernay
- **Commercial ingenuity**
  - Howard County water deal
- **Leveraging technology to create value**
  - Extensive water recycling in Permian & Montney
  - Montney real-time fibre-optic analysis of cluster effectiveness
  - Data analytics & automation

Conceptual Advanced Completions Design



Delivering Stronger Wells in Pipestone Montney



*Well results normalized to 9,000' lateral

INCREASING BUSINESS RESILIENCY

Managing Risk and Preserving Flexibility

- **Maintaining agility in a short-cycle capital business:**
  - Sophisticated planning & supply chain management
  - Just-in-time infrastructure avoids non-productive capital
  - Not creating long-term take-or-pay commitments
  - Current rig count is 5 rigs less than 2017 peak, as planned in original guidance
- **New Montney plant startups to reduce Canadian per unit T&P expense**
  - YTD Canadian T&P was $8.91/BOE
  - Incremental production flowing through new plants expected to have significantly lower per unit T&P cost
- **Strategic risk management for both Montney & Permian growth**
  - Combination of physical sales arrangements, firm transportation and active hedging programs
  - Focused on realized price optimization

FOCUS ON QUALITY CORPORATE RETURNS

- Strongly ahead in year one of five-year-plan
- Expanding margins
- Boosting productivity
- Managing inflation
- Commercial mindset delivering value
- Well positioned for 2018

NON-GAAP MEASURES

Certain measures in this presentation 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. These measures have been provided for meaningful comparisons between current results and other periods and should not be viewed as a substitute for measures reported under U.S. GAAP. For additional information regarding non-GAAP measures, including reconciliations, see the Company's website and Encana's most recent Annual Report as filed on SEDAR and EDGAR. Non-GAAP measures include:

- **Non-GAAP Cash Flow and Corporate Margin** – Non-GAAP Cash Flow (or Cash Flow) is defined as cash from operating activities excluding net change in other assets and liabilities, net change in non-cash working capital and current tax on sale of assets. Corporate Margin is 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 may be used, along with other measures, in the calculation of certain performance targets for the company's management and employees.
- **Net Debt, Adjusted EBITDA and Net Debt to Adjusted EBITDA** – Net Debt is defined as long-term debt, including the current portion, less cash and cash equivalents. Management uses this measure as a substitute for total long-term debt in certain internal debt metrics as a measure of the company's ability to service debt obligations and as an indicator of the company's overall financial strength. 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. Net Debt to Adjusted EBITDA is monitored by management as an indicator of the company's overall financial strength and as a measure considered comparable to peers in the industry.
- **Non-GAAP Operating Earnings (Loss)** – is 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 adjustments to normalize the effect of income taxes calculated using the estimated annual effective income tax rate.
- **Operating Margin/Operating Netback** – Product revenues less costs associated with delivering the product to market, including production, mineral and other taxes, transportation and processing and operating expenses. When presented on a per BOE basis, Operating Margin/Operating Netback is defined as indicated divided by average barrels of oil equivalent sales volumes. Operating Margin/Operating Netback is used by management as an internal measure of the profitability of a play(s).

FUTURE ORIENTED INFORMATION

This presentation contains certain forward-looking statements or information (collectively, “FLS”) within the meaning of applicable securities legislation. FLS include:

- expectation of meeting or exceeding the targets in Encana’s corporate guidance
- anticipated capital program, including focus of development, amount of development capital, the amount allocated to its core assets, number of wells on stream, expected return and source of funding thereof
- well performance, completions intensity, location of acreage and costs relative to peers and within assets
- anticipated production, including growth from core assets, cash flow, capital coverage, payout, net present value, rates of return, production efficiency, commodity mix, operating, income and corporate margins, netbacks and growth, including expected timeframes
- number of well locations (including potential premium well locations and ability to add to or consumption of such inventory), well spacing, decline rate, focus of drilling and timing, commodity composition, and operating performance compared to type curves
- pacesetting operational metrics being indicative of future well performance and costs, and sustainability thereof
- timing, success and benefits from innovation, cube development approach, advanced completions design, technology advancements and asset quality, including to drive efficiency and capital productivity and the transferability of ideas across portfolio
- expected capacity and transportation and processing commitments and restrictions
- anticipated reserves and resources, including product types and stacked resource potential
- competitiveness and pace of growth of Encana’s assets within North America and against its peers
- anticipated third-party incremental and joint venture carry capital
- ability to manage costs and maintain or enhance efficiencies, including drilling and completion, operating, corporate, transportation and processing costs, associated staffing levels, and sustainability of level of costs thereof
- expected net debt and debt ratios
- growth in long-term shareholder value and timing thereof
- expected rig count and rig release metrics
- commodity price outlook
- anticipated hedging and outcomes of risk management program, including exposure to certain commodity prices, amount of hedged production and physical sales locations
- management of Encana’s balance sheet and credit rating, including access to and commitment of credit facilities
- advancement of and expected growth and returns in Encana’s five-year plan, including projections based on commodity prices
- running room and scale of Encana’s assets and anticipated vertical and horizontal drilling
- anticipated dividends
- expected consideration from transactions, use of proceeds, satisfaction of closing conditions and timing thereof
- advantages of Encana’s multi-basin portfolio
- costs, capacity and timing of infrastructure being operational
- future outlook, including sources of funding, production, growth from core assets and leverage

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; Encana's ability to access its revolving credit facilities and shelf prospectuses; assumptions contained in Encana’s corporate guidance and in this presentation; 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; ability to satisfy closing conditions and regulatory approvals, successful closing of, and value of post-closing and other adjustments associated with announced sale of assets; 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, the benefits achieved and general industry expectations.

Risks and uncertainties that may affect these business outcomes include: the ability to generate sufficient cash flow to meet Encana's obligations; risks inherent to completing transactions on a timely basis or at all and adjustments that may impact expected proceeds or value to Encana; commodity price volatility; ability to secure adequate product transportation and potential pipeline curtailments; variability and discretion of Encana's board of directors to declare and pay dividends, if any; the timing and costs of well, facilities and pipeline construction; business interruption and casualty losses or unexpected technical difficulties; counterparty and credit risk; risk and effect of a downgrade in credit rating, and its impact on access to capital markets and other sources of liquidity; fluctuations in currency and interest rates; risks inherent in Encana's corporate guidance; failure to achieve anticipated results from 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 future lawsuits and regulatory actions made against Encana; impact to Encana as a result of disputes arising with its partners, including the suspension by its partners of certain of their obligations and the 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 natural gas and liquids 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 presentation and, except as required by law, Encana undertakes no obligation to update publicly or revise any FLS. The FLS contained in this presentation are expressly qualified by these cautionary statements.

Certain future oriented financial information or financial outlook information is included in this presentation to communicate current expectations as to Encana’s performance. Readers are cautioned that it may not be appropriate for other purposes. Rates of return for a particular asset or well are on a before-tax basis and are based on specified commodity prices with local pricing offsets, capital costs associated with drilling, completing and equipping a well, field operating expenses and certain type curve assumptions. Pacesetter well costs for a particular asset are a composite of the best drilling performance and best completions performance wells in the current quarter in such asset and are presented for comparison purposes. Drilling and completions costs have been normalized as specified in this presentation based on certain lateral lengths for a particular asset. Premium well locations are locations with expected after tax returns greater than 35% at $50/bbl WTI and $3/MMBtu NYMEX. For convenience, references in this presentation to “Encana”, the “Company”, “we”, “us” and “our” may, where applicable, refer only to or include any relevant direct and indirect subsidiary corporations and partnerships (“Subsidiaries”) of Encana Corporation, and the assets, activities and initiatives of such Subsidiaries.

ADVISORY REGARDING OIL & GAS INFORMATION

All proved and probable reserve and economic contingent resource estimates in this presentation are effective as of December 31, 2016, prepared by internal qualified reserves evaluators in accordance with procedures and standards contained in the Canadian Oil and Gas Evaluation Handbook ("COGEH"), National Instrument ("NI") 51-101 and SEC regulations, as applicable, and are audited by independent qualified reserves auditors engaged by Encana. Detailed Canadian protocol disclosure will be contained in Encana's Form 51-101F1 for the year-ended December 31, 2016 ("Form 51-101F1") and detailed U.S. protocol disclosure will be contained in Encana's Annual Report on Form 10-K for the year-ended December 31, 2016 ("Annual Report on Form 10-K"), each of which Encana anticipates filing with applicable securities regulatory authorities on or about February 27, 2017. Additional detail regarding Encana's economic contingent resources disclosure will be available in the Supplemental Disclosure Document filed concurrently with the Form 51-101F1. Information on the forecast prices and costs used in preparing the Canadian protocol estimates will be contained in the Form 51-101F1. For additional information relating to risks associated with such estimates, see "Item 1A. Risk Factors" in the Annual Report on Form 10-K.

Reserves are the estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, from a given date forward, based on: analysis of drilling, geological, geophysical and engineering data, the use of established technology, and specified economic conditions, which are generally accepted as being reasonable. Proved reserves are those reserves which can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves. Probable reserves are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves. Contingent resources do not constitute, and should not be confused with, reserves. Contingent resources are defined as those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations using established technology or technology under development, but which are not currently considered to be commercially recoverable due to one or more contingencies. There is uncertainty that it will be commercially viable to produce any portion of the resources. All of the resources classified as contingent are considered to be discovered, and as such have been assigned a 100% chance of discovery, but have however been risked for the chance of development. The chance of development is defined as the likelihood of a project being commercially viable and development proceeding in a timely fashion. Determining the chance of development requires taking into consideration each contingency and quantifying the risks into an overall development risk factor at a project level. Contingent resources are categorized as economic if those contingent resources have a positive net present value under currently forecasted prices and costs. In examining economic viability, the same fiscal conditions have been applied as in the estimation of Encana's reserves. Contingencies include factors such as required corporate or third party (such as joint venture partners) approvals, legal, environmental, political and regulatory matters or a lack of infrastructure or markets.

Encana uses the terms play, resource play, total petroleum initially-in-place ("PIIP"), natural gas-in-place ("NGIP"), and crude oil-in-place ("COIP"). Play encompasses resource plays, geological formations and conventional plays. Resource play describes an accumulation of hydrocarbons known to exist over a large areal expanse and/or thick vertical section, which when compared to a conventional play, typically has a lower geological and/or commercial development risk and lower average decline rate. PIIP is defined by the Society of Petroleum Engineers - Petroleum Resources Management System ("SPE-PRMS") as that quantity of petroleum that is estimated to exist originally in naturally occurring accumulations. It includes that quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations prior to production plus those estimated quantities in accumulations yet to be discovered (equivalent to "total resource potential"). NGIP and COIP are defined in the same manner, with the substitution of "natural gas" and "crude oil" where appropriate for the word "petroleum". As used by Encana, estimated ultimate recovery ("EUR"), which Encana may refer to as recoverable resource potential, has the meaning set out jointly by the Society of Petroleum Engineers and World Petroleum Congress in the year 2000, being those quantities of petroleum which are estimated, on a given date, to be potentially recoverable from an accumulation, plus those quantities already produced therefrom.

Encana has provided information with respect to its assets which are "analogous information" as defined in NI 51-101, including estimates of PIIP, NGIP, COIP, EUR and production type curves. This analogous information is presented on a basin, sub-basin or area basis utilizing data derived from Encana's internal sources, as well as from a variety of publicly available information sources which are predominantly independent in nature. Production type curves are based on a methodology of analog, empirical and theoretical assessments and workflow with consideration of the specific asset, and as depicted in this presentation, is representative of Encana's current program, including relative to current performance, but are not necessarily indicative of ultimate recovery. Some of this data may not have been prepared by qualified reserves evaluators, may have been prepared based on internal estimates, and the preparation of any estimates may not be in strict accordance with COGEH. Estimates by engineering and geo-technical practitioners may vary and the differences may be significant. Encana believes that the provision of this analogous information is relevant to Encana's oil and gas activities, given its acreage position and operations (either ongoing or planned) in the areas in question, and such information has been updated as of the date hereof unless otherwise specified. Due to the early life nature of the various emerging plays discussed in this presentation, PIIP is the most relevant specific assignable category of estimated resources. There is no certainty that any portion of the resources will be discovered. There is no certainty that it will be commercially viable to produce any portion of the estimated PIIP, NGIP, COIP or EUR. Estimates of well locations and premium return well inventory include proved, probable, contingent and unbooked locations. These estimates are prepared internally based on Encana's prospective acreage and are based on an assumption as to the number of wells that can be drilled per section based on industry practice and internal review. Approximately 36 percent of all locations specified in our core assets are booked as either reserves or resources, as prepared by internal qualified reserves evaluators using forecast prices and costs as of December 31, 2016. Unbooked locations do not have attributed reserves or resources and have been identified by management as an estimation of Encana's multi-year drilling activities based on evaluation of applicable geologic, seismic, engineering, production and reserves information. There is no certainty that Encana will drill all unbooked locations and if drilled there is no certainty that such locations will result in additional oil and gas reserves, resources or production. The locations on which Encana will actually drill wells, including the number and timing thereof is ultimately dependent upon the availability of capital, regulatory and partner approvals, seasonal restrictions, equipment and personnel, oil and natural gas prices, costs, actual drilling results, additional reservoir information that is obtained, production rate recovery, transportation constraints and other factors. While certain of the unbooked locations have been de-risked by drilling existing wells in relative close proximity to such locations, many of other unbooked locations are farther away from existing wells where management has less information about the characteristics of the reservoir and therefore there is more uncertainty whether wells will be drilled in such locations and if drilled there is more uncertainty that such wells will result in additional proved or probable reserves, resources or production.

30-day IP and other short-term rates are not necessarily indicative of long-term performance or of ultimate recovery. 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.