ENCANA CORPORATION

Q2 2016 Results Conference Call

July 21, 2016

BEATING 2016 TARGETS AND POSITIONED FOR GROWTH

- Lower cash costs – additional $100 million savings
- Lower D&C costs – 30-40% reduction
- Higher returns – over 35% ATROR
- Raising 2016 production – up by 10,000 BOE/d
- Increasing 2016 D&C activity – 50% more wells for 20% more capital
- Strengthened balance sheet – reducing net debt
- Poised for growth in 2017

2016 GUIDANCE UPDATE

Lower Costs, Higher Core Four Production

- **Driving down cash costs by $100 million**
  - Operating cost guidance down 11%
  - T&P guidance down 5%
- **Driving industry leading D&C costs lower and re-investing savings plus adding to core four capital**
  - Core four 4Q15 to 4Q16 decline down by half - from 10% to 5%
  - Increased total production guidance**
- **2016 D&C activity up 50% for only 20% more capital**
  - Allocated to high returns & margins
  - 70% of capital increase to be spent in Q4
  - 30,000 – 35,000 BOE/d incremental production in 2017
  - Incremental capital allocated across core four with majority to Permian
- **Significantly reduced commitments**
  - Gordondale sale reduces total commitments by $275MM
  - DJ Basin sale reduces total commitments by $25MM
  - Reduced 2016-2018 REX commitment by $350MM
- **Expect to reduce net debt for second straight year**

	2016 Guidance (Feb 24, 2016)	Revised 2016 Guidance
Capital Investment		
Capital Investment ($MM)	900 – 1,000	1,100 – 1,200
Production		
Natural Gas (MMcf/d)	1,300 – 1,400	1,300 – 1,400
Total Liquids (Mbbls/d)	120 – 130	120 – 130
% Oil & Condensate*	75 – 80%	75 – 80%
% Natural Gas Liquids	20 – 25%	20 – 25%
Total Production (MBOE/d)	340 – 360	340 – 360
Total Production** (ex. Gordondale) (MBOE/d)	330 – 350	340 – 360
Cash Costs		
PMOT ($/BOE)	0.75 – 0.85	0.75 – 0.85
Upstream Operating ($/BOE)	4.60 – 4.90	4.15 – 4.35
Transportation & Processing ($/BOE)	6.80 – 7.20	6.60 – 6.70
G&A*** ($/BOE)	1.25 – 1.35	1.30 – 1.40

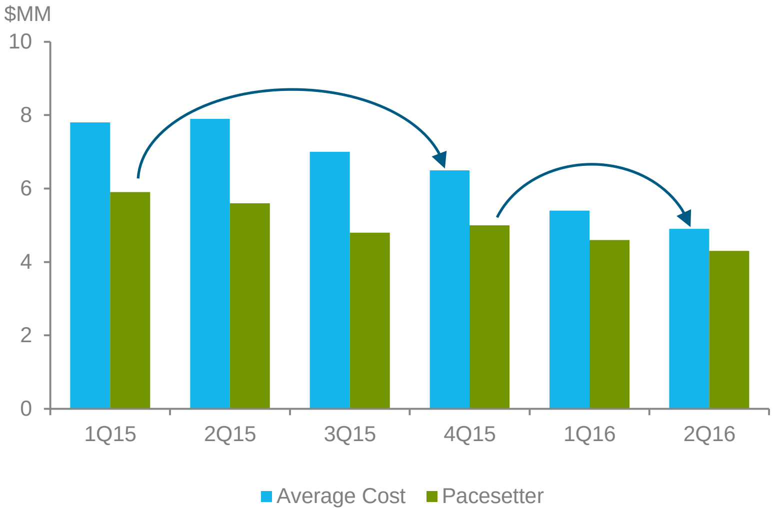
* Includes plant & field condensate **Adjusted for Gordondale divestiture ***Excluding restructuring and long-term incentive costs

PACESETTING WELLS

Relentless focus on capital efficiency

- **Pacesetters are a leading indicator of future costs**
- **Driven by innovation**
  - Structured approach to testing new ideas/technologies
- **Successful ideas and technologies are rapidly implemented at scale**
  - Consistently converting pacesetter cost performance into subsequent quarterly average
  - Successes are transferred across portfolio

Permian Quarterly D&C Performance

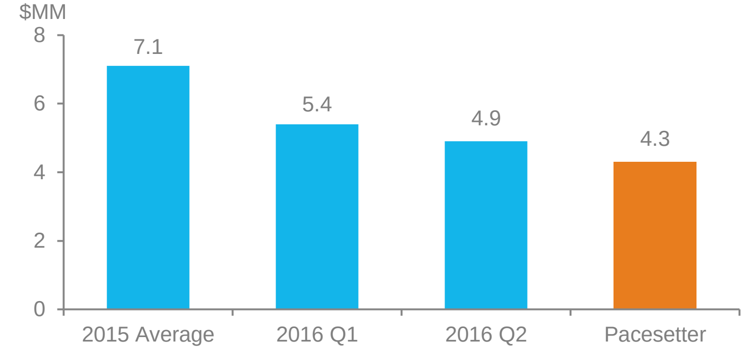


PERMIAN

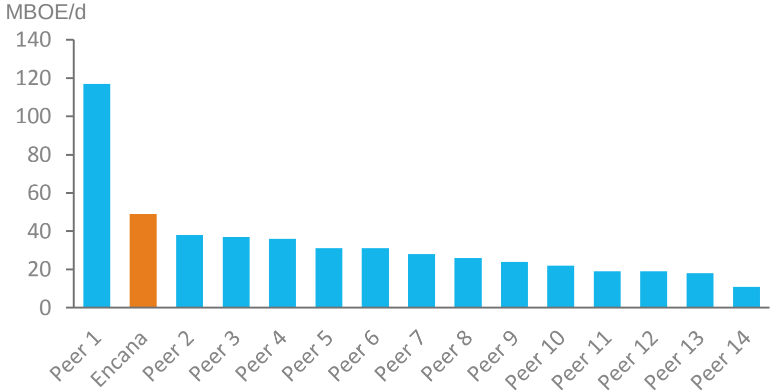
Basin Leading Operator

- **New pacesetting D&C cost of $4.3 MM**
  - Average D&C cost of $4.9 MM/well in Q2, down 31% from 2015
- **Davidson 14-well pad producing >10,000 BOE/d**
  - Only 120 days from first spud to on production
  - Exceeded ½ million BOE in 50 days
  - Estimated 2016 production efficiency of $20,000/BOE/d
  - Potential for 60 total locations on this pad
- **Encana is the second largest core Midland Basin producer**
- **Total vertical retention program complete for 2016**
  - 50% reduction from guidance, $25 MM savings
  - ~100 locations outstanding 2017+
  - Continuing work of converting retention wells into horizontals

Aggressive reductions in D&C Costs*



Encana is the second largest Midland Basin producer**

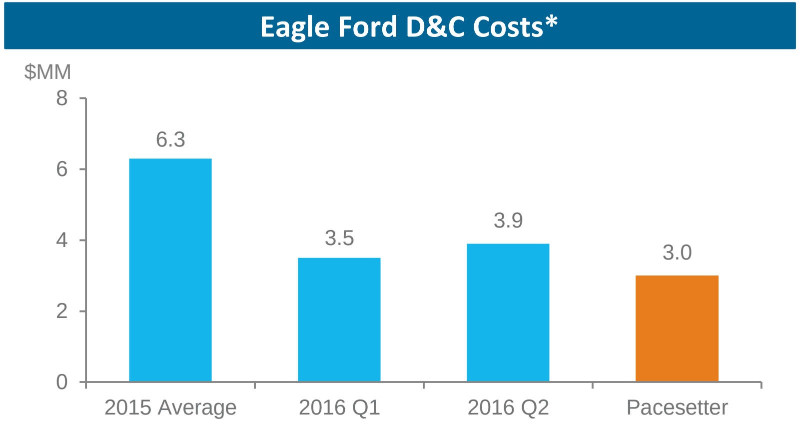


* D&C Costs normalized to 7,500 ft lateral length ** Source: Drilling Info, Inc., all production from Glasscock, Howard, Midland, and Martin

EAGLE FORD

Continued Cost Improvements

- **New pacesetting D&C cost of $3.0 MM**
  - Pacesetting drill in 8.5 days
  - Average D&C cost of $3.9 MM/well in Q2, down 38% from 2015
- **Increasing productivity and reducing costs**
  - Improving base well performance
    - Focusing on highest return opportunities
  - Optimized chemical program
    - ~25% cost reduction in chemical use
  - Debottlenecking the Eagle Ford
    - Delivering production uplift



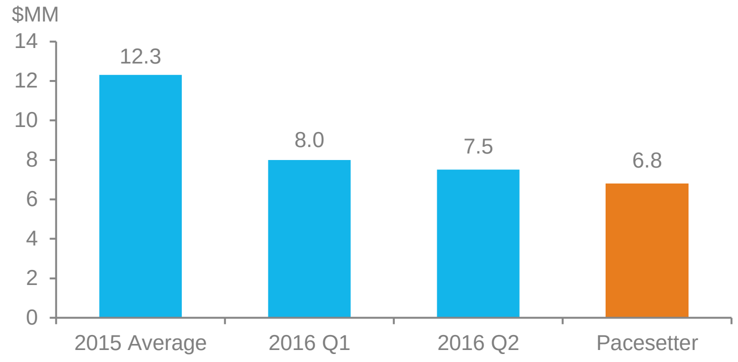
* D&C Costs normalized to 5,000 ft lateral length

DUVERNAY

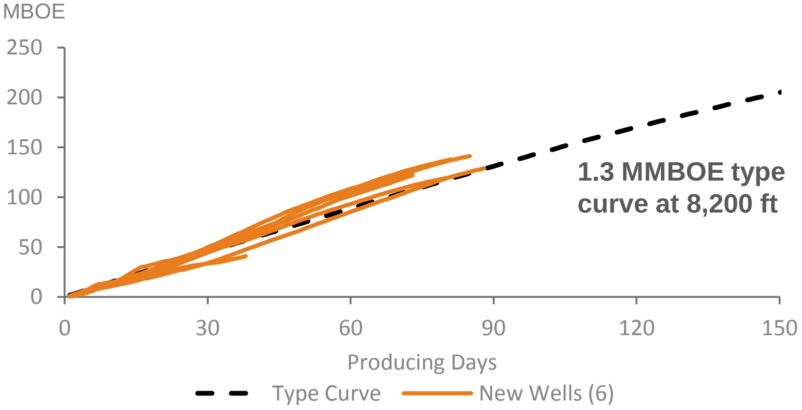
Leading Productivity and Costs

- **New pacesetting D&C cost of $6.8 MM**
  - Average D&C cost of $7.5 MM/well in Q2, down ~40% from 2015
- **~50% of production is condensate**
  - Volumes reported at the plant and not the wellhead
- **Latest Simonette South pad**
  - Averaging 100 MBOE/well in 60 days, ~50% condensate

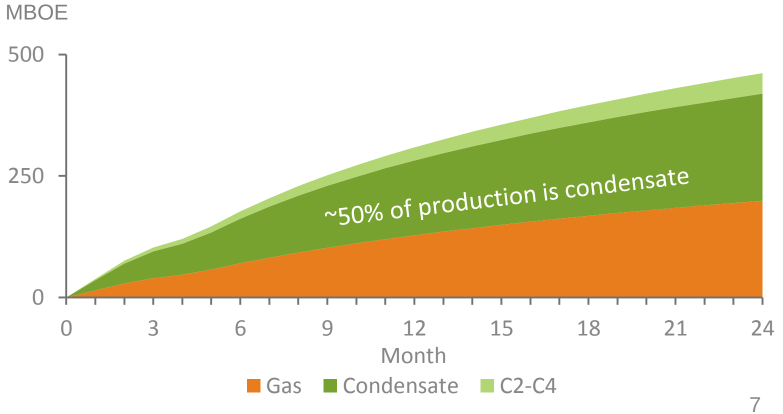
Duvernay D&C Costs*



Simonette South 14-6 Pad Production



Duvernay Type Well By Product



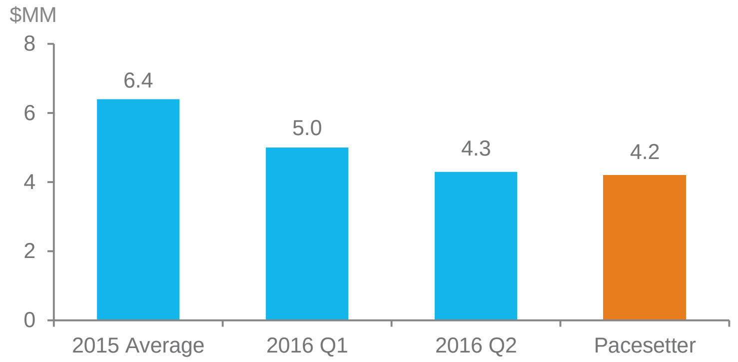
* D&C Costs normalized to 8,200 ft lateral length

MONTNEY

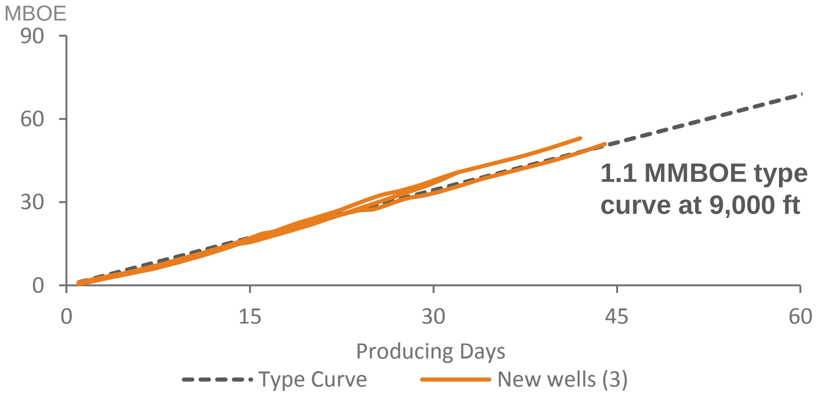
Focusing on the Condensate

- **New pacesetting D&C cost of $4.2 MM**
  - Average D&C cost of $4.3 MM/well in Q2, down 33% from 2015
- **Growing Montney liquids**
  - 2016 program averaging >75 bbls/MMcf condensate
- **Pipestone new wells**
  - On pace for 50 MBOE/well in 45 days at 700 bbls/MMcf
- **Encouraged by progress on negotiations to reduce TCPL tolls**

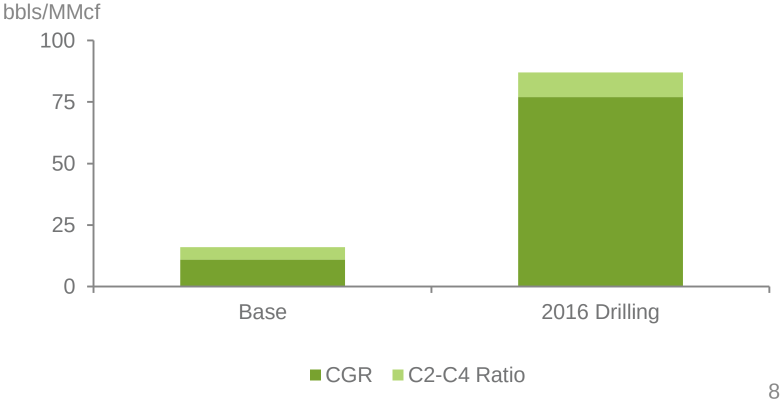
Cutbank D&C Cost Reductions*



Pipestone New Well Production



Montney Liquids Growth



* D&C Costs normalized to 9,000 ft lateral length

Q2 HIGHLIGHTS

Strong Operational Execution

- **Q2 upstream operating cash flow excluding hedge up ~100% versus Q1**
- **Significant reduction in cash costs**
  - REX renegotiation & optimized utilization
  - LOE task force delivering savings
- **Highly disciplined capital allocation**
  - 95% YTD capex focused on core four assets
- **Strong operational performance**
  - Continue to capture capital efficiencies
  - Core four scale maintained
  - Core four production 73% of total production

	Q1 2016	Q2 2016
Upstream Operating Cash Flow* Excluding Hedging ($MM)	103	204
Upstream Operating Cash Flow* Including Hedging ($MM)	280	330
Transportation & Processing ($/BOE)	7.07	6.80
Operating ($/BOE)	4.35	3.63
PMOT ($/BOE)	0.65	0.89
Total Cash Flow ($MM)	102	182
- $ per share, diluted	0.12	0.21
Operating Earnings (Loss) ($MM)	(130)	89
- $ per share, diluted	(0.15)	0.10
Capital Investment ($MM)	359	215
Net Debt** ($MM)	5,180	5,397
Natural Gas (MMcf/d)	1,516	1,418
Total Liquids (Mbbls/d)	130.8	132.0
Total Production (MBOE/d)	383.4	368.3
Core Four Production (MBOE/d)	269.1	268.3

*Upstream operating cash flow is defined as revenues, net of royalties, less production and mineral and other taxes, transportation and processing and operating expenses for each of the respective Canadian and USA operations.
**Net debt is defined as debt less cash and cash equivalents.

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One. Agile. Driven.
A culture of success

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 2016 corporate guidance
- expected proceeds from divestitures, expectation that the closing conditions and regulatory approvals will be satisfied, the timing of closing thereof and the use of proceeds therefrom, including expected reduction to debt and increase in capital investment
- Encana's 2016 capital program, including the amount allocated to its core four assets
- well performance, completions intensity and costs relative to peers and within plays
- anticipated production, cash flow, rates of return and growth
- number of well locations, decline rate, focus of drilling and operating performance compared to type curves
- pacesetting operational metrics being indicative of average future well performance and costs
- ability to scale or redirect capital program and innovation and asset quality to drive capital productivity
- expected capacity and impact of transportation and storage restrictions
- anticipated capital and cost efficiencies, including drilling and completion, operating, corporate, transportation and processing costs, and sustainability thereof
- expected interest expense savings
- growth in long-term shareholder value
- reductions to cash outlay
- anticipated hedging and outcomes of risk management program, including amount of hedged production
- management of Encana's balance sheet and credit rating, including access to and commitment of credit facilities and upcoming debt maturities
- the expectation to continue to strengthen Encana's balance sheet and create additional financial flexibility
- 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 for results to differ materially from those expressed or implied. These assumptions include:

- assumptions contained in Encana's 2016 corporate guidance and in this presentation
- data contained in key modeling statistics
- availability of attractive hedges and enforceability of risk management program
- results from innovations
- expectation that counterparties will fulfill their obligations under gathering, midstream and marketing agreements
- access to transportation and processing facilities where Encana operates
- effectiveness of Encana's resource play hub model to drive productivity and efficiencies
- enforceability of transaction agreements and the ability of the parties to such transactions to satisfy closing conditions and regulatory approvals and the value of adjustments to the expected proceeds
- 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: risks inherent to closing announced divestitures on a timely basis or at all and adjustments that may reduce the expected proceeds and value to Encana; commodity price volatility; timing and costs of well, facilities and pipeline construction; ability to secure adequate product transportation and potential pipeline curtailments; business interruption and casualty losses or unexpected technical difficulties; counterparty and credit risk; fluctuations in currency and interest rates; risk and effect of a downgrade in credit rating, including below an investment-grade credit rating, and its impact on access to capital markets and other sources of liquidity; variability and discretion of Encana's Board to declare and pay dividends, if any; the ability to generate sufficient cash flow to meet Encana's obligations; failure to achieve anticipated results from cost and efficiency initiatives; risks inherent in marketing operations; risks associated with technology; Encana's ability to acquire or find additional reserves; imprecision of reserves estimates and estimates of recoverable quantities of natural gas and liquids from resource plays and other sources not currently classified as proved, probable or possible reserves or economic contingent resources, including future net revenue estimates; changes in or interpretation of royalty, tax, environmental, accounting and other laws; risks associated with past and future divestitures of certain assets or other transactions or receive 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 MD&A, financial statements, Annual Information Form and Form 40-F, 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. This presentation may contain references to non-GAAP measures, which do not have any standardized meaning and therefore are unlikely to be comparable to similar measures presented by other companies. These measures are presented to provide shareholders and potential investors with additional information regarding Encana's liquidity and its ability to generate funds to finance its operations. Rates of return for a particular play 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 play are a composite of the best drilling performance and best completions performance wells in the current quarter in such play 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 play.

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 RESERVES DATA & OTHER OIL & GAS INFORMATION

National Instrument ("NI") 51-101 of the Canadian Securities Administrators imposes oil and gas disclosure standards for Canadian public companies engaged in oil and gas activities. Encana complies with NI 51-101 requirements in its most recently filed annual information form ("AIF"). Detailed Canadian protocol disclosure is contained in Appendix A and under "Narrative Description of the Business" of the AIF. Certain disclosure is also prepared in accordance with U.S. disclosure requirements as set forth in Appendix D of the AIF. A description of the primary differences between the disclosure requirements under Canadian and U.S. standards is set forth under the heading "Reserves and Other Oil and Gas Information" in the AIF. Additional detail regarding Encana's economic contingent resources disclosure is in the Supplemental Disclosure Document filed concurrently with the AIF. All estimates are effective as of December 31, 2015, are derived from reports prepared by independent qualified reserves evaluators ("IQREs) engaged by Encana and are prepared in accordance with procedures and standards contained in the Canadian Oil and Gas Evaluation Handbook ("COGEH"), NI 51-101 and SEC regulations, as applicable. Information on the forecast prices and costs used in preparing the estimates are contained in the AIF. For additional information relating to risks associated with the estimates of reserves and resources, see "Risk Factors" in the AIF.

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 resources"). 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") 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 certain of its plays and emerging opportunities which is "analogous information" as defined in NI 51-101. This analogous information includes estimates of PIIP, NGIP, COIP or EUR, all as defined in the COGEH or by the SPE-PRMS, 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. 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. Disclosure of estimated well locations include proved, probable, contingent and unbooked locations. These estimates are prepared internally based on Encana's prospective acreage and an assumption as to the number of wells that can be drilled per section based on industry practice and internal review. Approximately 20 percent of all locations in the play are booked as either reserves or resources, as prepared by IQREs using forecast prices and costs as of December 31, 2015. 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.