



take a closer look



Encana Corporation

Key Resource Play Statistics

As at June 30, 2011

encanaTM

natural gas





Definitions

Supply Cost: The flat NYMEX natural gas price that yields a risked internal rate of return of 9% and does not include land or G&A costs

EUR: Estimated ultimate volume of recoverable hydrocarbons, reflective of basin-wide performance expectations, based on best estimate reserves

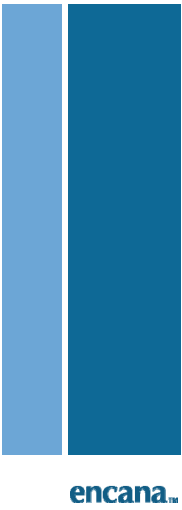
PIR 0% (Profit Investment Ratio): Undiscounted net present value divided by undiscounted capital investment

PIR 9% (Profit Investment Ratio): Net present value discounted at 9% divided by capital investment discounted at 9%

Texas Overview

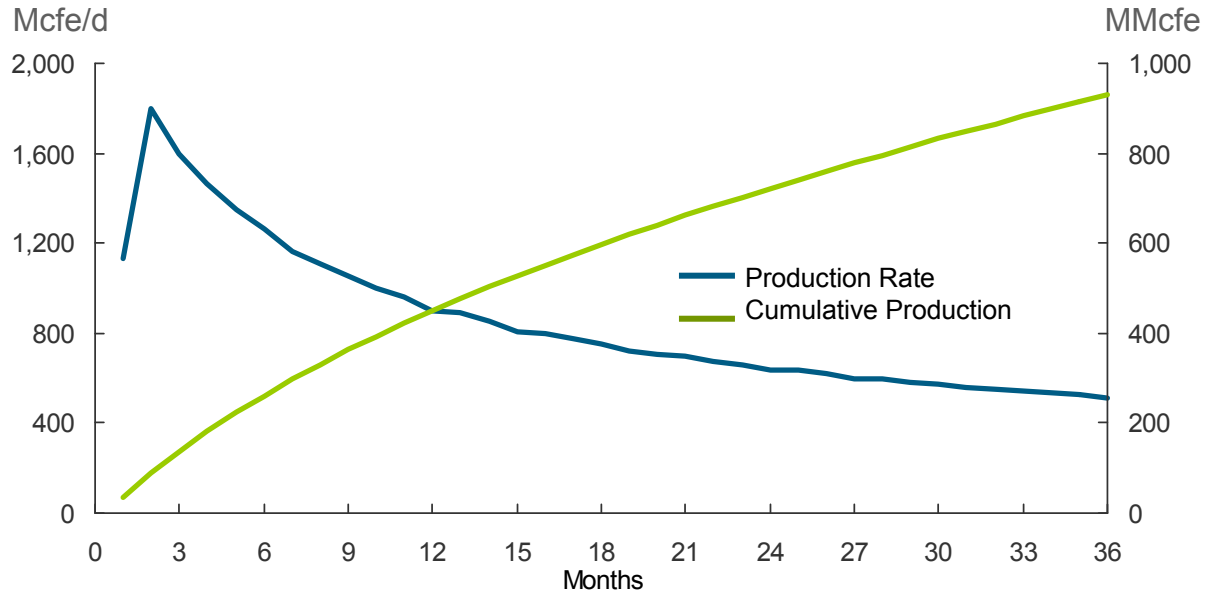
	2009	2010	2011F
Total Capital (\$MM)	466	418	340
Total Production (MMcfe/d)	473	488	375
Drilling Activity (net wells)	65	52	60
Operating Costs (\$/Mcf)	0.79	0.72	1.05
Transportation & Selling (\$/Mcf)	0.78	0.85	0.92
Royalty Rate (%)	26	26	26
Supply Cost* (\$/MMBtu NYMEX)	3.96	3.86	3.00 – 3.50
Net Producing wells (12/31/10)	1,034		
Net drilling inventory (1P + 1C)	1,300		
Net drilling inventory (2P + 2C)	1,800		

*2011F supply cost reflects the new drilling portion of the 2011 capital program. Texas KRP includes Fort Worth, Deep Bossier, East Texas Shelf and Sabine.



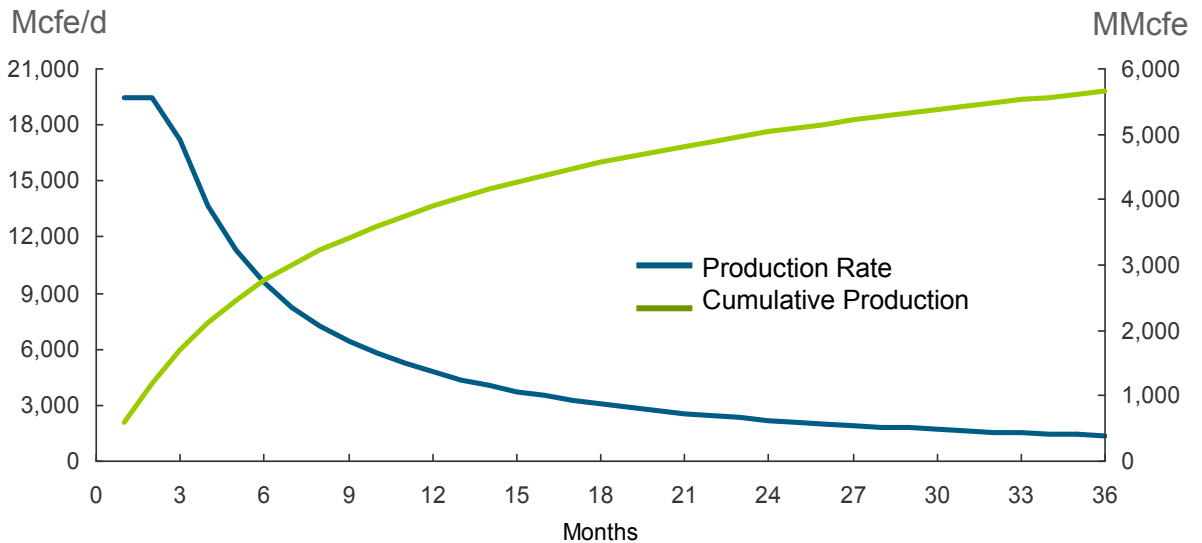
Texas

Type Curve – Fort Worth



DCT Cost (\$MM/well): 3.4	Avg. Heat Content (Btu/scf): 920 – 1,250
30 day IP rate (MMcfe/d): 1.8	PIR @ 0%: 1.97
EUR (Bcfe/well): 2.0 – 3.0	PIR @ 9%: 0.78
Wells per section: 12 – 32	After tax IRR (%): 35

Type Curve – Deep Bossier



DCT Cost (\$MM/well): 10.3	Avg. Heat Content (Btu/scf): 1,050
30 day IP rate (MMcfe/d): 19.4	PIR @ 0%: 0.96
EUR (Bcfe/well): 5.0 – 8.0	PIR @ 9%: 0.57
Wells per section: 4 – 8	After tax IRR (%): 66

Type curves for 2011 drilling program, presented on a gross before royalty basis.

Jonah, Wyoming

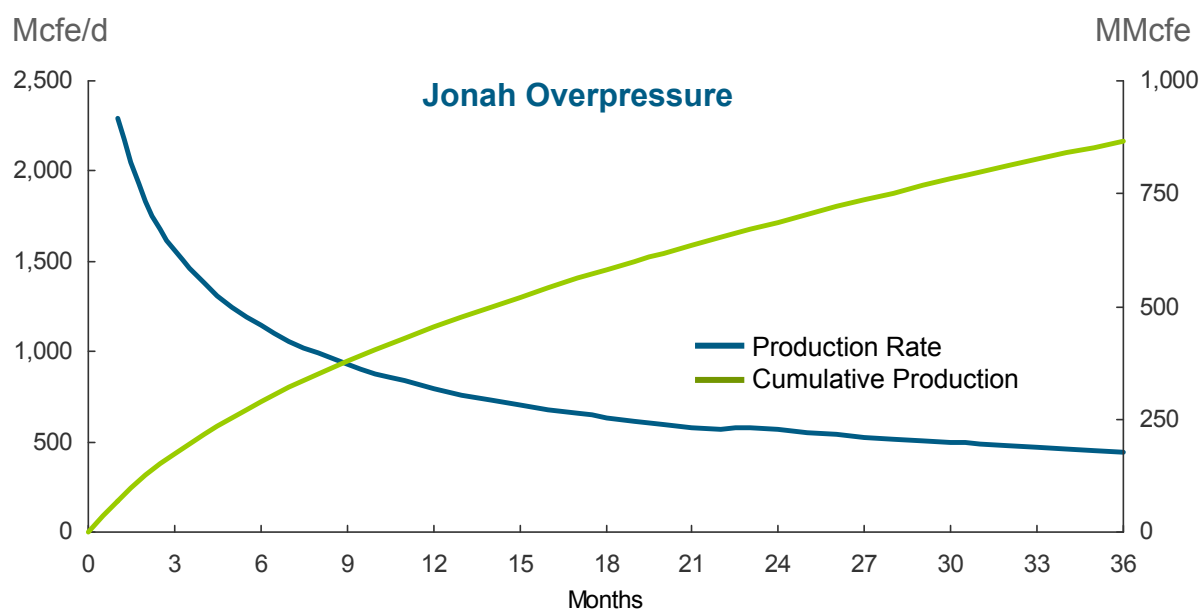
Overview

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	2009	2010	2011F
Total Capital (\$MM)	346	374	280
Total Production (MMcfe/d)	601	559	500
Drilling Activity (net wells)	108	112	70
Operating Costs (\$/Mcf)	0.18	0.28	0.25
Transportation & Selling (\$/Mcf)	0.44	0.54	0.80
Royalty Rate (%)	21	21	22
Supply Cost* (\$/MMBtu NYMEX)	3.50 – 4.00	3.25 – 4.00	1.00 – 4.00
Net Producing Wells (12/31/10)	1,135		
Net Drilling Inventory (1P + 1C)	700		
Net Drilling Inventory (2P + 2C)	1,500		

*2011F supply cost reflects the new drilling portion of the 2011 capital program.

Type Curve



DCT Cost (\$MM/well): 3.1	Avg. Heat Content (Btu/scf): 1,120
30 day IP rate (MMcfe/d): 2.2	PIR @ 0%: 1.15
EUR (Bcfe/well): 1.8 – 2.5	PIR @ 9%: 0.50
Wells per section: 60 – 80	After tax IRR (%): 25

Type curve for 2011 drilling program, presented on a gross before royalty basis. Metrics include funding leveraged through joint ventures.

Piceance, Colorado

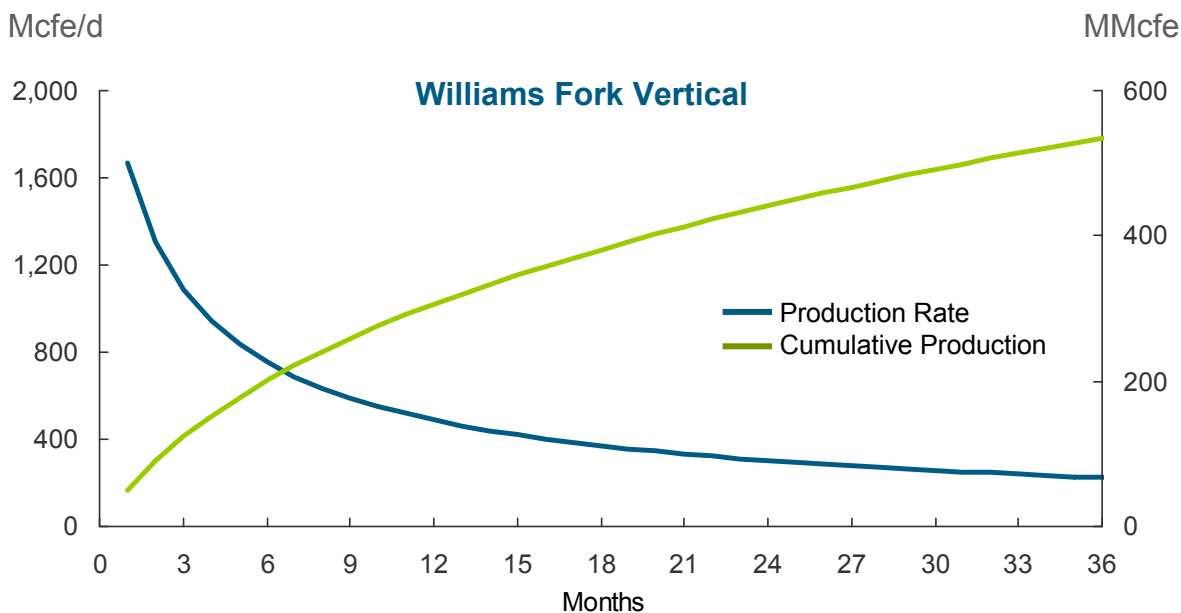
Overview

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	2009	2010	2011F
Total Capital (\$MM)	183	224	525
Total Production (MMcfe/d)	373	458	450
Drilling Activity (net wells)	129	125	165
Operating Costs (\$/Mcf)	0.46	0.56	0.65
Transportation & Selling (\$/Mcf)	1.20	1.47	1.45
Royalty Rate (%)	14	14	14
Supply Cost* (\$/MMBtu NYMEX)	1.00 – 4.25	1.00 – 4.00	1.00 – 4.00
Net Producing Wells (12/31/10)	2,845		
Net Drilling Inventory (1P + 1C)	1,800		
Net Drilling Inventory (2P + 2C)	5,400		

*2011F supply cost reflects the new drilling portion of the 2011 capital program.

Type Curve



DCT Cost (\$MM/well): 2.0	Avg. Heat Content (Btu/scf): 1,060 – 1,150
30 day IP rate (MMcfe/d): 1.7	PIR @ 0%: 1.95
EUR (Bcfe/well): 1.0 – 2.0	PIR @ 9%: 0.77
Wells per section: 32	After tax IRR (%): 30

Type curve for 2011 drilling program, presented on a gross before royalty basis. Metrics include funding leveraged through joint ventures.

Haynesville, Louisiana

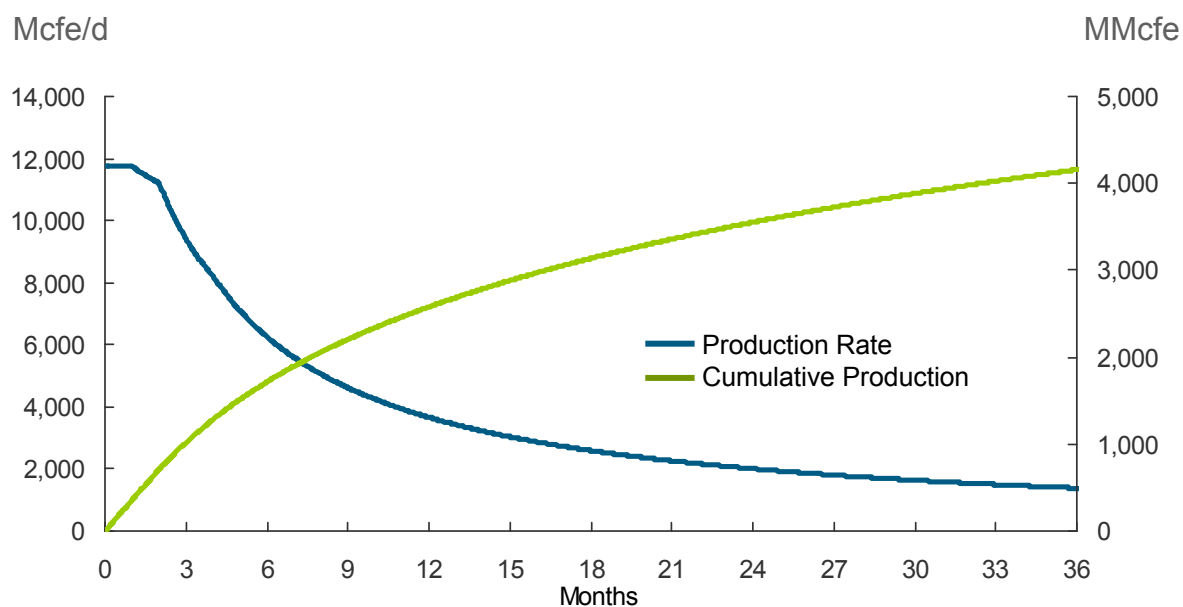
Overview

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	2009	2010	2011F
Total Capital (\$MM)	521	1,141	980
Total Production (MMcfe/d)	61	287	505
Drilling Activity (net wells)	48	100	85
Operating Costs (\$/Mcf)	1.14	0.59	0.55
Transportation & Selling (\$/Mcf)	0.37	0.46	0.85
Royalty Rate (%)	21	19	20
Supply Cost* (\$/MMBtu NYMEX)	4.46	4.70	3.50 – 4.00
Net Producing Wells (12/31/10)	132		
Net Drilling Inventory (1P + 1C)	1,300		
Net Drilling Inventory (2P + 2C)	2,600		

*2011F supply cost reflects the new drilling portion of the 2011 capital program.

Type Curve



DCT Cost (\$MM/well): 9.3	Avg. Heat Content (Btu/scf): 1,000
30 day IP rate (MMcfe/d): 11.8	PIR @ 0%: 0.90
EUR (Bcfe/well): 5.0 – 8.0	PIR @ 9%: 0.35
Wells per section: 1 – 8	After tax IRR (%): 27

Type curve for 2011 drilling program, presented on a gross before royalty basis.
 2010 metrics based on 85% lease retention activity and 15% resource play hub activity.
 2011 metrics based on 30% lease retention activity and 70% resource play hub activity.

Jean Marie, British Columbia

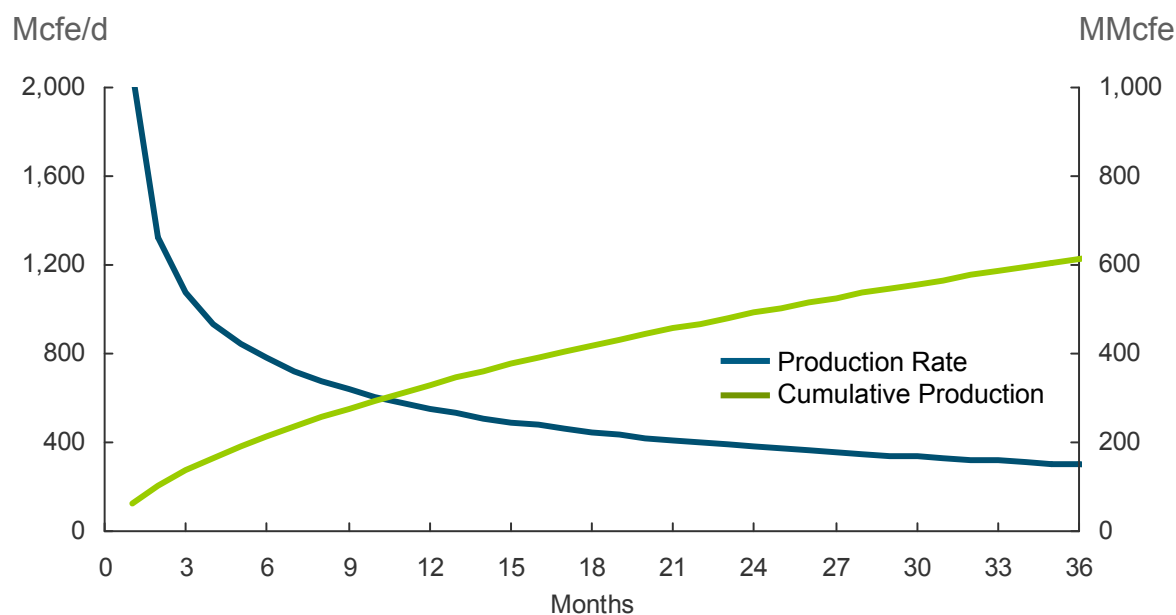
Overview

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	2009	2010	2011F
Total Capital (\$MM)	82	109	85
Total Production (MMcfe/d)	195	207	165
Drilling Activity (net wells)	36	31	20
Operating Costs (\$/Mcf)	0.91	1.05	1.40
Transportation & Selling (\$/Mcf)	0.58	0.34	0.30
Royalty Rate (%)	8.5	6	9 – 13
Supply Cost* (\$/MMBtu NYMEX)	3.58 – 4.06	3.24 – 4.06	3.50 – 4.00
Net Producing Wells (12/31/10)	1,045		
Net Drilling Inventory (1P + 1C)	500		
Net Drilling Inventory (2P + 2C)	900		

*2011F supply cost reflects the new drilling portion of the 2011 capital program.

Type Curve



DCT Cost (\$MM/well): 2.5 – 2.9	Avg. Heat Content (Btu/scf): 1,030
30 day IP rate (MMcfe/d): 2.5 – 3.0	PIR @ 0%: 1.00 – 1.20
EUR (Bcef/well): 1.1 – 1.8	PIR @ 9%: 0.45 – 0.55
Wells per section: 1 - 3	After tax IRR (%): 26 - 33

Jean Marie is a subset of the Greater Sierra key resource play.
Type curve for 2011 drilling program, presented on a gross before royalty basis.

Horn River, British Columbia

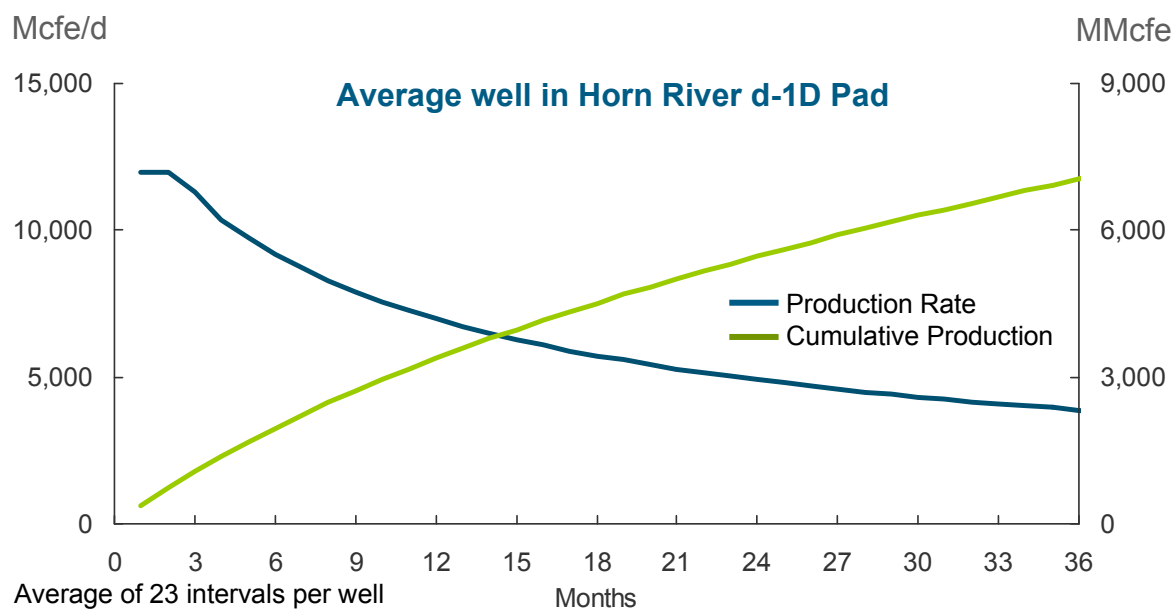
Overview

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	2009	2010	2011F
Total Capital (\$MM)	216	406	265
Total Production (MMcfe/d)	9	29	95
Drilling Activity (net wells)	21	16	10
Operating Costs (\$/Mcf)	1.58	0.73	0.65
Transportation & Selling (\$/Mcf)	0.81	0.81	0.80
Royalty Rate (%)	10	3	2
Supply Cost* (\$/MMBtu NYMEX)	5.00 – 6.00	3.90 – 4.40	3.75 – 4.00
Net Producing wells (12/31/10)	21.5		
Net Drilling Inventory (1P + 1C)	600		
Net Drilling Inventory (2P + 2C)	800		

*2011F supply cost reflects the new drilling portion of the 2011 capital program.

Type Curve



DCT Cost (\$MM/well): 15 – 17	Avg. Heat Content (Btu/scf): 1,005
30 day IP rate (MMcfe/d): 9 – 15	PIR @ 0%: 2.00 – 2.20
EUR (Bcfe/well): 16 - 20	PIR @ 9%: 0.75 – 0.85
Wells per pad: 8 – 16	After tax IRR (%): 23 – 29

Horn River is a subset of the Greater Sierra key resource play.
 Metrics reflect lease boundary economics for pad drilling locations only.
 Type curve for 2011 drilling program, presented on a gross before royalty basis.
 EUR range applies to wells drilled since 2010.

Cutbank Ridge, Alberta/B.C

Overview

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	2009	2010	2011F
Total Capital (\$MM)	467	506	610
Total Production (MMcfe/d)	379	461	510
Drilling Activity (net wells)	71	62	70
Operating Costs (\$/Mcf)	0.90	0.75	0.84
Transportation & Selling (\$/Mcf)	0.34	0.38	0.40
Royalty Rate (%)	12	8	12
Supply Cost* (\$/MMBtu NYMEX)	3.50 – 4.00	2.22 – 3.74	3.00 – 3.50
Net Producing Wells (12/31/10)	904		
Net Drilling Inventory (1P + 1C)	1,700		
Net Drilling Inventory (2P + 2C)	2,700		

*2011F supply cost reflects the new drilling portion of the 2011 capital program
Cutbank Ridge includes the Montney.

Montney, Alberta/B.C.

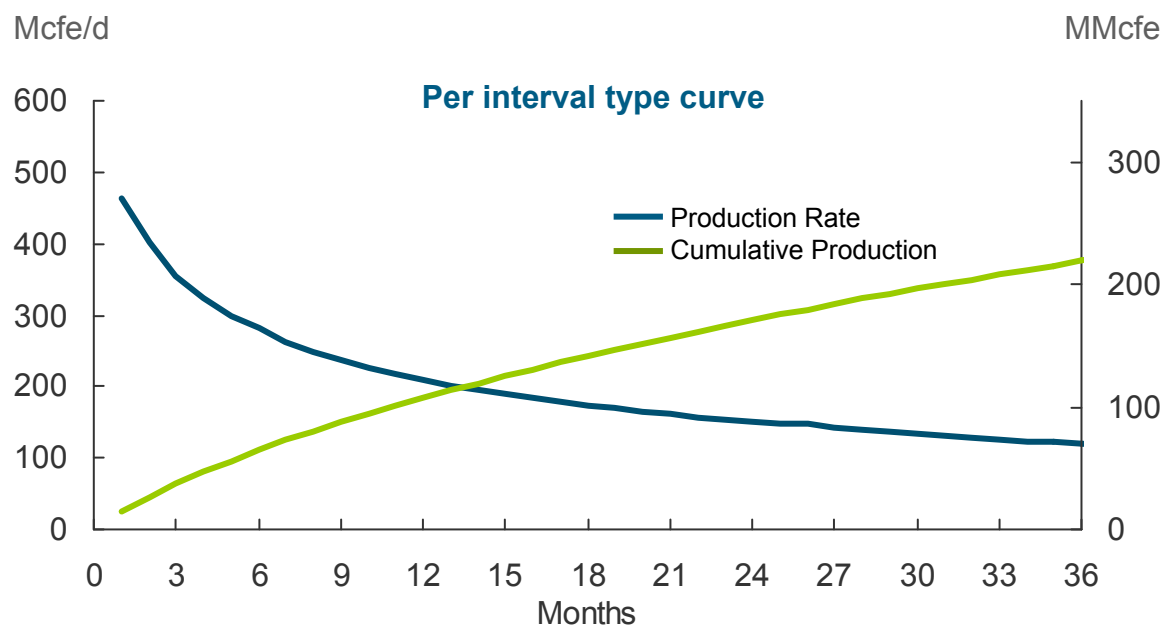
Overview

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	2009	2010	2011F
Total Capital (\$MM)	389	405	485
Total Production (MMcfe/d)	173	274	350
Drilling Activity (net wells)	64	54	60
Operating Costs (\$/Mcf)	0.90	0.75	0.85
Transportation & Selling (\$/Mcf)	0.34	0.38	0.40
Royalty Rate (%)	12	8	11
Supply Cost* (\$/MMBtu NYMEX)	3.50 – 4.00	2.22 – 3.74	2.15 – 3.25
Net Producing Wells (12/31/10)	351		
Net Drilling Inventory (1P + 1C)	1,600		
Net Drilling Inventory (2P + 2C)	2,500		

*2011F supply cost reflects the new drilling portion of the 2011 capital program.

Type Curve



DCT Cost (\$MM/interval): 0.40 – 0.55	Avg. Heat Content (Btu/scf): 965 – 1,100
30 day IP rate (MMcfe/d): 5 – 9	PIR @ 0%: 2.00 – 2.40
EUR (Bcfe/well): 4 – 12	PIR @ 9%: 0.70 – 1.00
Wells per section: 4 – 8	After tax IRR (%): 30 – 38

Type curve for 2011 drilling program, presented on a gross before royalty basis.
 Montney is a subset of the Cutbank Ridge resource play.
 EUR depends on number of completion stages.

Bighorn, Alberta

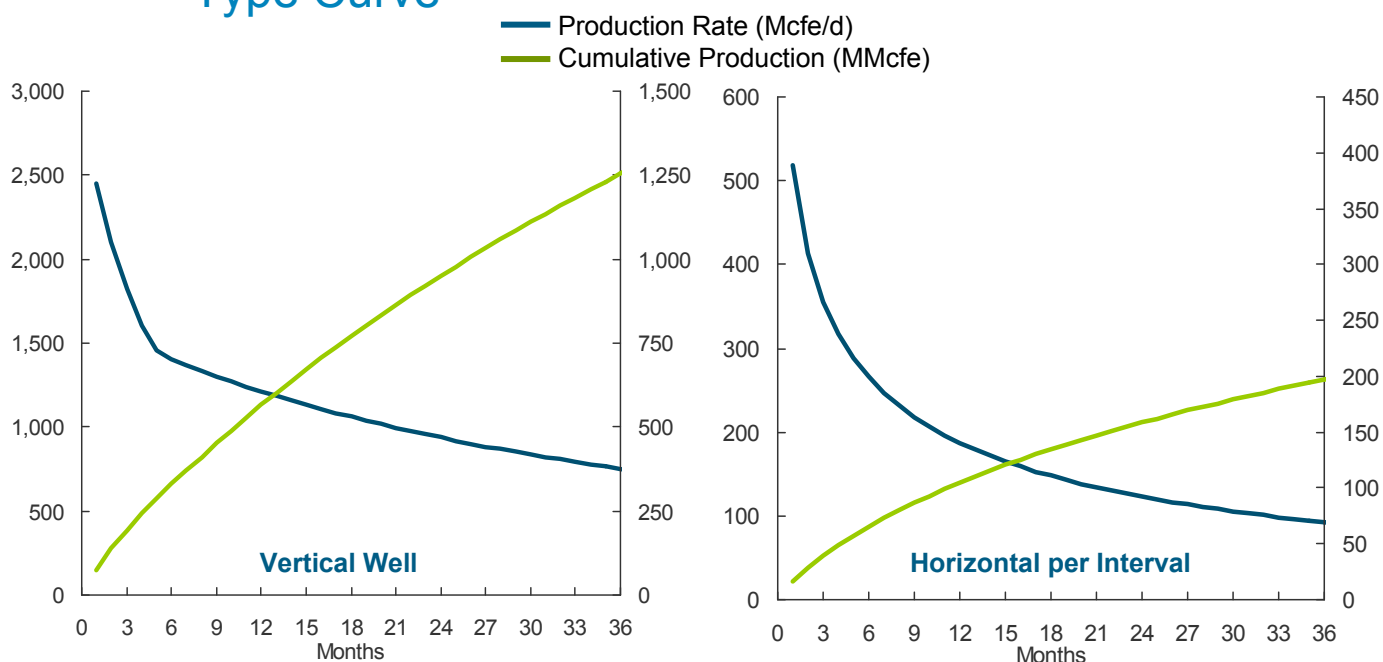
Overview

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	2009	2010	2011F
Total Capital (\$MM)	272	345	435
Total Production (MMcfe/d)	176	240	255
Drilling Activity (net wells)	69	51	70
Operating Costs (\$/Mcfe)	1.06	0.90	1.10
Transportation & Selling (\$/Mcfe)	0.34	0.38	0.40
Royalty Rate (%)	13	6	9
Supply Cost* (\$/MMBtu NYMEX)	3.75 – 4.00	2.75 – 3.45	2.90 – 3.30
Net Producing Wells (12/31/10)	342		
Net Drilling Inventory (1P + 1C)	600		
Net Drilling Inventory (2P + 2C)	1,200		

*2011F supply cost reflects the new drilling portion of the 2011 capital program.

Type Curve



DCT Cost (\$MM/well): 4.5 – 7.8	Avg. Heat Content (Btu/scf): 1,100
30 day IP rate (MMcfe/d): 2 – 4	PIR @ 0%: 1.40 – 1.90
EUR (Bcfe/well): 2 – 7	PIR @ 9%: 0.60 – 0.80
Wells per section: 2 – 8	After tax IRR (%): 32 – 40

Type curves for 2011 drilling program, presented on a gross before royalty basis.
 Type curves reflect a blend of Fahler, Wilrich and Dunvegan plays.

CBM, Alberta

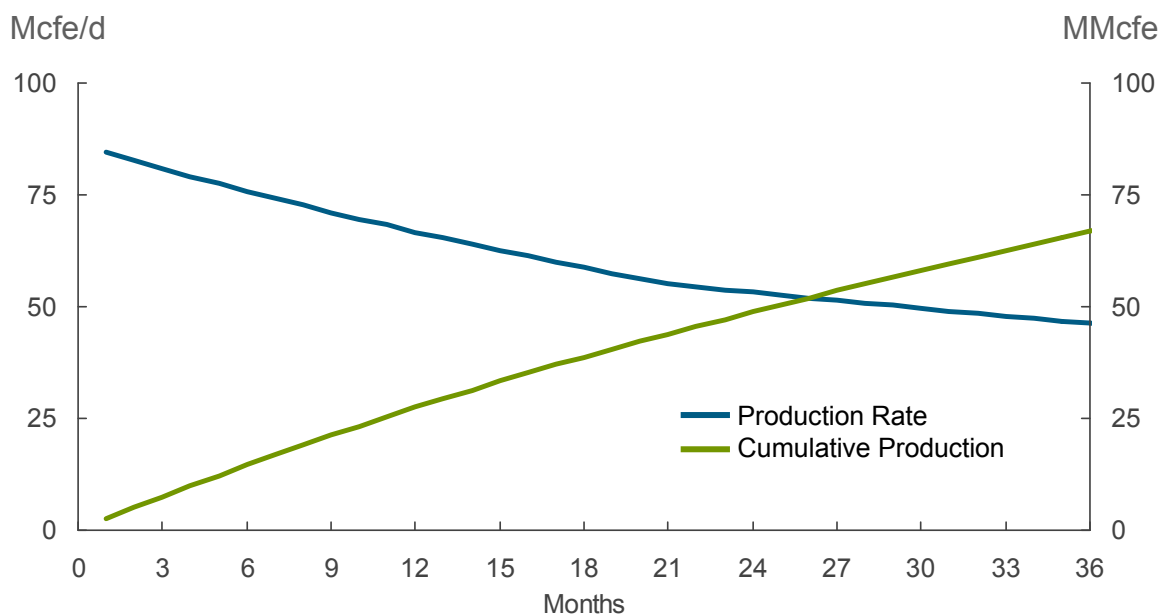
Overview

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	2009	2010	2011F
Total Capital (\$MM)	313	428	340
Total Production (MMcfe/d)	450	431	455
Drilling Activity (net wells)	502	1,044	450
Operating Costs (\$/Mcf)	0.99	1.13	1.25
Transportation & Selling (\$/Mcf)	0.15	0.15	0.15
Royalty Rate (%)	1	1	2
Supply Cost* (\$/MMBtu NYMEX)	3.50 – 4.25	3.50 – 3.75	3.25 – 3.50
Net Producing Wells (12/31/10)	9,696		
Net Drilling Inventory (1P + 1C)	15,300		
Net Drilling Inventory (2P + 2C)	15,900		

*2011F supply cost reflects the new drilling portion of the 2011 capital program.

Type Curve



DCT Cost (\$MM/well): 0.3	Avg. Heat Content (Btu/scf): 1,000
30 day IP rate (MMcfe/d): 0.1	PIR @ 0%: 2.20
EUR (Bcfe/well): 0.2 – 0.3	PIR @ 9%: 0.90
Wells per section: 4 – 16	After tax IRR (%): 30

Type curve for 2011 drilling program, presented on a gross before royalty basis.



Future Oriented Information

In the interests of providing Encana shareholders and potential investors with information regarding Encana, including management's assessment of Encana's and its subsidiaries' future plans and operations, certain statements contained in this presentation are forward-looking statements or information within the meaning of applicable securities legislation, collectively referred to herein as "forward-looking statements." Forward-looking statements in this presentation include, but are not limited to: 2011 estimated capital, production, drilling activities, operating costs, transportation and selling costs, royalty rate, and supply cost; estimated after tax IRR, returns at the various rates of various resource plays, type curves of various plays, the estimated associated drilling inventories, EUR, wells per section, IP rates, and DCT cost of these plays.

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Readers are cautioned not to place undue reliance on forward-looking statements, as there can be no assurance that the plans, intentions or expectations upon which they are based will occur. By their nature, forward-looking statements involve numerous assumptions, known and unknown risks and uncertainties, both general and specific, that contribute to the possibility that the predictions, forecasts, projections and other forward-looking statements will not occur, which may cause the company's actual performance and financial results in future periods to differ materially from any estimates or projections of future performance or results expressed or implied by such forward-looking statements. These assumptions, risks and uncertainties include, among other things: the risk that the company may not conclude potential joint venture arrangements with others and attract third party capital; volatility of and assumptions regarding commodity prices; assumptions based upon the company's current guidance; fluctuations in currency and interest rates; product supply and demand; market competition; risks inherent in the company's and its subsidiaries' marketing operations, including credit risks; imprecision of reserves and resources 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; marketing margins; potential disruption or unexpected technical difficulties in developing new facilities; unexpected cost increases or technical difficulties in constructing or modifying processing facilities; risks associated with technology; the company's ability to replace and expand natural gas reserves; its ability to generate sufficient cash flow from operations to meet its current and future obligations; its ability to access external sources of debt and equity capital; the timing and the costs of well and pipeline construction; the company's ability to secure adequate product transportation; changes in royalty, tax, environmental, greenhouse gas, carbon, accounting and other laws or regulations or the interpretations of such laws or regulations; political and economic conditions in the countries in which the company operates; terrorist threats; risks associated with existing and potential future lawsuits and regulatory actions made against the company; and other risks and uncertainties described from time to time in the reports and filings made with securities regulatory authorities by Encana. Although Encana believes that 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 foregoing list of important factors is not exhaustive. Forward-looking statements with respect to anticipated production, reserves and production growth, including over five years or longer, are based upon numerous facts and assumptions, including a projected capital program averaging approximately \$6 billion per year, that underlies the long-range plan of Encana which is subject to review annually and to such revisions for factors including the outlook for natural gas commodity prices and the expectations for capital investment by the company achieving an average rate of approximately 2,500 net wells per year, Encana's current net drilling location inventory, natural gas price expectations over the next few years, production expectations made in light of advancements in horizontal drilling, multi-stage fracture stimulation and multi-well pad drilling, the current and expected productive characteristics of various existing and emerging resource plays, Encana's estimates of proved, probable and possible reserves and economic contingent resources, expectations for rates of return which may be available at various prices for natural gas and current and expected cost trends. In addition, assumptions relating to such forward-looking statements generally include Encana's current expectations and projections made in light of, and generally consistent with, its historical experience and its perception of historical trends, including the conversion of resources into reserves and production as well as expectations regarding rates of advancement and innovation, generally consistent with and informed by its past experience, all of which are subject to the risk factors identified elsewhere in this presentation.

Furthermore, the forward-looking statements contained in this presentation are made as of the date of this presentation, and, except as required by law, Encana does not undertake any obligation to update publicly or to revise any of the included forward-looking statements, whether as a result of new information, future events or otherwise. The forward-looking statements contained in this presentation are expressly qualified by this cautionary statement.



Advisory Regarding Reserves Data and Other Oil & Gas Information Disclosure Protocols

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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. In previous years, Encana relied upon an exemption from Canadian securities regulatory authorities to permit it to provide disclosure relating to reserves and other oil and gas information in accordance with U.S. disclosure requirements. As a result of the expiry of that exemption, Encana is providing disclosure which complies with the annual disclosure requirements of NI 51-101 in its Annual Information Form dated February 17, 2011 (AIF). The Canadian protocol disclosure is contained in Appendix A and under “Narrative Description of the Business” in the AIF. Encana has obtained an exemption dated January 4, 2011 from certain requirements of NI 51-101 to permit it to provide certain disclosure prepared in accordance with U.S. disclosure requirements, in addition to the Canadian protocol disclosure. That disclosure is primarily set forth in Appendix D of the AIF. A description of the primary differences between the disclosure requirements under the Canadian standards and the disclosure requirements under the U.S. standards is set forth under the heading “Reserve Quantities and Other Oil and Gas Information” in the AIF.

The estimates of economic contingent resources contained in this presentation are based on definitions contained in the Canadian Oil and Gas Evaluation Handbook. Contingent resources do not constitute, and should not be confused with, reserves. Contingent resources are defined as those quantities of petroleum estimated, on 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. Economic contingent resources are those contingent resources that are currently economically recoverable. In examining economic viability, the same fiscal conditions have been applied as in the estimation of reserves. There is a range of uncertainty of estimated recoverable volumes. A low estimate is considered to be a conservative estimate of the quantity that will actually be recovered. It is likely that the actual remaining quantities recovered will exceed the low estimate, which under probabilistic methodology reflects a 90% confidence level. A best estimate is considered to be a realistic estimate of the quantity that will actually be recovered. It is equally likely that the actual remaining quantities recovered will be greater or less than the best estimate, which under probabilistic methodology reflects a 50% confidence level. A high estimate is considered to be an optimistic estimate. It is unlikely that the actual remaining quantities recovered will exceed the high estimate, which under probabilistic methodology reflects a 10% confidence level. There is no certainty that it will be commercially viable to produce any portion of the volumes currently classified as economic contingent resources. The primary contingencies which currently prevent the classification of Encana’s disclosed economic contingent resources as reserves are the lack of a reasonable expectation that all internal and external approvals will be forthcoming and the lack of a documented intent to develop the resources within a reasonable time frame. Other commercial considerations that may preclude the classification of contingent resources as reserves include factors such as legal, environmental, political and regulatory matters or a lack of markets.

The estimates of various classes of reserves (proved, probable, possible) and of contingent resources (low, best, high) in this presentation represent arithmetic sums of multiple estimates of such classes for different properties, which statistical principles indicate may be misleading as to volumes that may actually be recovered. Readers should give attention to the estimates of individual classes of reserves and contingent resources and appreciate the differing probabilities of recovery associated with each class.

In this presentation, certain crude oil and NGLs volumes have been converted to cubic feet equivalent (cfe) on the basis of one barrel (bbl) to six thousand cubic feet (Mcf). Cfe may be misleading, particularly if used in isolation. A conversion ratio of one bbl to six Mcf is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent value equivalency at the well head.

Encana uses the terms resource play, total petroleum initially-in-place, natural gas-in-place, and crude oil-in-place. Resource play is a term used by Encana to describe 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. Total petroleum initially-in-place (“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”). Natural gas-in-place (“NGIP”) and crude oil-in-place (“COIP”) are defined in the same manner, with the substitution of “natural gas” and “crude oil” where appropriate for the word “petroleum”.

In this presentation, Encana has provided information with respect to certain of its Key Resource Plays and emerging opportunities which is “analogous information” as defined in NI 51-101. This analogous information includes estimates of PIIP, NGIP or COIP, all as defined in the Canadian Oil & Gas Evaluation Handbook (“COGEH”) or by the SPE-PRMS, and/or 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. Some of this data may not have been prepared by qualified reserves evaluators or auditors and the preparation of any estimates may not be in strict accordance with COGEH. Regardless, 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.

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.

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