Enercom Inc.

The Oil & Services Conference

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Brian Ector, Vice President, Investor Relations

BAYTEX ENERGY CORP.

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Advisory

Forward Looking Statements

In the interest of providing Baytex's shareholders and potential investors with information regarding Baytex, including management's assessment of Baytex's future plans and operations, certain statements made by the presenter and contained in these presentation materials (collectively, this "presentation") are "forward-looking statements" within the meaning of the United States Private Securities Litigation Reform Act of 1995 and "forward-looking information" within the meaning of applicable Canadian securities legislation (collectively, "forward-looking statements"). The forward-looking statements contained in this presentation speak only as of the date of this presentation and are expressly qualified by this cautionary statement.

Specifically, this presentation contains forward-looking statements relating to: our business strategies, plans and objectives; our ability to fund our capital expenditures and dividends on our common shares from funds from operations; oil and natural gas production in 2011; production growth rates; our dividend policy; capital expenditures; funds from operations for the fourth quarter of 2011; drilling and operational plans; reserves and reserve life index; the net present value of our reserves and contingent resource; our long range plan for 2012-2017, including production decline rates, number of wells to be drilled, dividends on our common shares, effective cash income tax rates, production and funds from operations growth rates, our ability to fund our capital expenditures and dividends on our common shares from funds from operations and annual production volumes; our Seal heavy oil resource play, including original oil in place, the viability and economics of long-term commercial development using primary (cold) and thermal development, number of potential drilling locations, drilling and completion costs, initial production rates, estimated recoverable reserves, finding and development and operating costs, recovery factors, production efficiency ratios, steam-oil ratios, the pre-tax present value (unrisked) per barrel of recoverable reserve, the timing of completing a commercial scale thermal development using a 10-well module; and our assessment of the cyclic steam pilot projects at Harmon Valley and Cliffdale; our Lloydminster heavy oil property, including reserve life index, 2011 capital expenditures, drilling and operational plans for 2011, number of potential drilling locations, efficiency ratios, netbacks and recycle ratios; our Kerrobert steam-assisted gravity drainage project, including steam-oil ratios, number of potential drilling locations, expansion of steam capacity, capital expenditures and estimated recoverable reserves; rates of return for our heavy oil projects; profit/investment ratios for North American resource plays; pricing differentials between light, medium and heavy gravity crude oils; proposed pipeline infrastructure development; the supply of crude oil from Western Canada; pipeline capacity for Western Canadian crude oil; refining and upgrading capacity for heavy oil; the demand and supply outlook for heavy oil; our Bakken/Three Forks and Viking light oil resource plays, including initial production rates, estimated recoverable reserves, drilling and completion costs per well, the number of potential drilling locations, rates of return, number of prospective sections of land, potential development of middle Bakken zone, and drilling and operational plans for 2011; the existence, operation and strategy of our risk management program, including the portion of future exposures that have been hedged; our debt to EBITDA, debt to funds from operations, interest coverage, debt to reserves and debt to enterprise value ratios; our 2011 funds from operations; our 2011 year-end debt to funds from operations ratio; the sensitivity of our 2011 funds from operations to changes in West Texas Intermediate oil prices, natural gas prices, heavy oil differentials and Canada-United States foreign exchange rates; the taxation of our dividends; and our valuation based on various metrics customarily used in the oil and gas industry relative to other oil-weighted Canadian producers. In addition, information and statements relating to reserves are deemed to be forward-looking statements, as they involve implied assessment, based on certain estimates and assumptions, that the reserves described exist in quantities predicted or estimated, and that the reserves can be profitably produced in the future. Cash dividends on our common shares are paid at the discretion of our Board of Directors and can fluctuate. In establishing the level of cash dividends, the Board of Directors considers all factors that it deems relevant, including, without limitation, the outlook for commodity prices, our operational execution, the amount of funds from operations and capital expenditures and our prevailing financial circumstances at the time.

Advisory (Cont.)

These forward-looking statements are based on certain key assumptions regarding, among other things: petroleum and natural gas prices and pricing differentials between light, medium and heavy gravity crude oils; well production rates and reserve volumes; our ability to add production and reserves through our exploration and development activities; capital expenditure levels; the receipt, in a timely manner, of regulatory and other required approvals; the availability and cost of labour and other industry services; the amount of future cash dividends that we intend to pay; interest and foreign exchange rates; and the continuance of existing and, in certain circumstances, proposed tax and royalty regimes. The reader is cautioned that such assumptions, although considered reasonable by Baytex at the time of preparation, may prove to be incorrect.

Actual results achieved during the forecast period will vary from the information provided herein as a result of numerous known and unknown risks and uncertainties and other factors. Such factors include, but are not limited to: fluctuations in market prices for petroleum and natural gas; fluctuations in foreign exchange or interest rates; general economic, market and business conditions; stock market volatility and market valuations; changes in income tax laws; industry capacity; geological, technical, drilling and processing problems and other difficulties in producing petroleum and natural gas reserves; uncertainties associated with estimating petroleum and natural gas reserves; liabilities inherent in oil and natural gas operations; competition for, among other things, capital, acquisitions of reserves, undeveloped lands and skilled personnel; risks associated with oil and gas operations; changes in royalty rates and incentive programs relating to the oil and gas industry; changes in environmental and other regulations; incorrect assessments of the value of acquisitions; failure to obtain the necessary regulatory approvals on the planned timelines; and other factors, many of which are beyond the control of Baytex. These risk factors are discussed in Baytex's Annual Information Form, Annual Report on Form 40-F and Management's Discussion and Analysis for the year ended December 31, 2010, as filed with Canadian securities regulatory authorities and the U.S. Securities and Exchange Commission.

There is no representation by Baytex that actual results achieved during the forecast period will be the same in whole or in part as those forecast and Baytex 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, except as may be required by applicable securities law.

Oil and Gas Information

This presentation contains estimates as of May 1, 2011 of the volumes of, and the net present value of the future net revenue from, the "contingent resource" for three of our oil resource plays: the Bluesky in the Seal area of Alberta; the Bakken/Three Forks in North Dakota; and the Viking in southeast Alberta and southwest Saskatchewan. These estimates were prepared by our independent qualified reserves evaluator, Sproule Associates Limited ("Sproule").

"Contingent resource" is not, and should not be confused with, petroleum and natural gas reserves. "Contingent resource" is defined in the Canadian Oil and Gas Evaluation Handbook 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. Contingencies may include factors such as economic, legal, environmental, political and regulatory matters or a lack of markets. It is also appropriate to classify as contingent resource the estimated discovered recoverable quantities associated with a project in the early evaluation stage."

Advisory (Cont.)

A range of contingent resource estimates (low, best and high) were prepared by Sproule. A low estimate (C1) is considered to be a conservative estimate of the quantity of the resource that will actually be recovered. It is likely that the actual remaining quantities recovered will exceed the low estimate. Those resources at the low end of the estimate range have the highest degree of certainty (a 90% confidence level) that the actual quantities recovered will be equal or exceed the estimate. A best estimate (C2) is considered to be the best estimate of the quantity of the resource that will actually be recovered. It is equally likely that the actual remaining quantities recovered will be greater or less than the best estimate. Those resources that fall within the best estimate have a 50% confidence level that the actual quantities recovered will be equal or exceed the estimate. A high estimate (C3) is considered to be an optimistic estimate of the quantity of the resource that will actually be recovered. It is unlikely that the actual remaining quantities of resource recovered will meet or exceed the high estimate. Those resources at the high end of the estimate range have a lower degree of certainty (a 10% confidence level) that the actual quantities recovered will equal or exceed the estimate.

The primary contingencies which currently prevent the classification of the contingent resource as reserves consist of: preparation of firm development plans, including determination of the specific scope and timing of the project; project sanction; access to capital markets; stakeholder and regulatory approvals; access to required services and field development infrastructure; oil prices; demonstration of economic viability; future drilling program and testing results; further reservoir delineation and studies; facility design work; limitations to development based on adverse topography or other surface restrictions; and the uncertainty regarding marketing and transportation of petroleum from development areas.

There is no certainty that it will be commercially viable to produce any portion of the contingent resource or that Baytex will produce any portion of the volumes currently classified as contingent resource. The estimates of contingent resource involve implied assessment, based on certain estimates and assumptions, that the resource described exists in the quantities predicted or estimated and that the resource can be profitably produced in the future. The net present value of the future net revenue from the contingent resource does not necessarily represent the fair market value of the contingent resource.

The recovery and resource estimates provided herein are estimates only. Actual contingent resource (and any volumes that may be reclassified as reserves) and future production from such contingent resource may be greater than or less than the estimates provided herein.

Baytex has adopted the standard of 6 Mcf:1 BOE when converting natural gas to BOEs. BOEs may be misleading, particularly if used in isolation. A BOE conversion ratio of 6 Mcf:1 BOE is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

Non-GAAP Financial Measures

This presentation refers to funds from operations, which does not have any standardized meaning prescribed by generally accepted accounting principles in Canada ("GAAP"). We define funds from operations as cash flow from operating activities adjusted for financing costs, changes in non-cash operating working capital and other operating items. We believe that this measure assists in providing a more complete understanding of certain aspects of our results of operations and financial performance, including our ability to generate the cash flow necessary to fund future dividends to shareholders and capital investments. However, funds from operations should not be construed as an alternative to traditional performance measures determined in accordance with GAAP, such as cash flow from operating activities and net income. Please refer to our most recent management's discussion and analysis of financial condition and results of operations for a reconciliation of funds from operations to cash flow from operating activities. contains estimates as of May 1, 2011 of the volumes of, and the net present value of the future net revenue from, the "contingent resource" for three of our oil resource plays: the Bluesky in the Seal area of Alberta; the Bakken/Three Forks in North Dakota; and the Viking in southeast Alberta and southwest Saskatchewan. These estimates were prepared by our independent qualified reserves evaluator, Sproule.

Summary

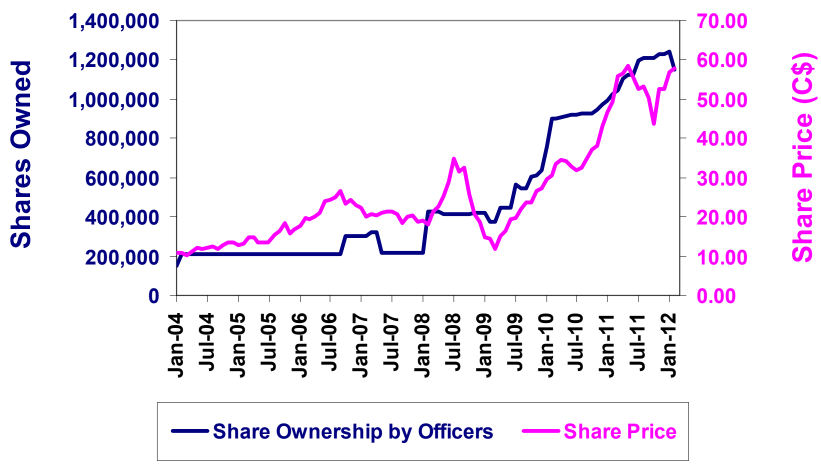
- Sustainable model: Dividend + organic oil growth generally within internally-generated cash flow
- Focus on dividend growth + per share growth in production, reserves and cash flow
- Sector-leading capital efficiency
- Technical focus
- Long-term, low-cost development inventory in both heavy and light oil
- Conservative payout ratio and strong balance sheet
- Long-term market out-performance and compelling valuation

Summary of Securities

Common Shares	
Trading Symbol	TSX / NYSE: BTE
Average Daily Volume (1)	TSX: 495,500 / NYSE: 212,200
Shares Outstanding (Current)	118.5 million
Market Value of Equity / Enterprise Value	C$6.8 billion / C$7.5 billion
Monthly Dividend	C$0.22/share
Dividend Yield (2)	4.6%
Cumulative Cash Distributions / Dividends	C$1.3 billion
9.15% Series A Senior Unsecured Debentures (3)	
Principal Outstanding	C$150 million
Maturity Date	August 2016
Current Price / Yield-to-Worst	$107.00 / 4.5%
6.75% Series B Senior Unsecured Debentures	
Principal Outstanding	US$150 million
Maturity Date	February 2021
Current Price / Yield-to-Worst	$102.00 / 6.4%

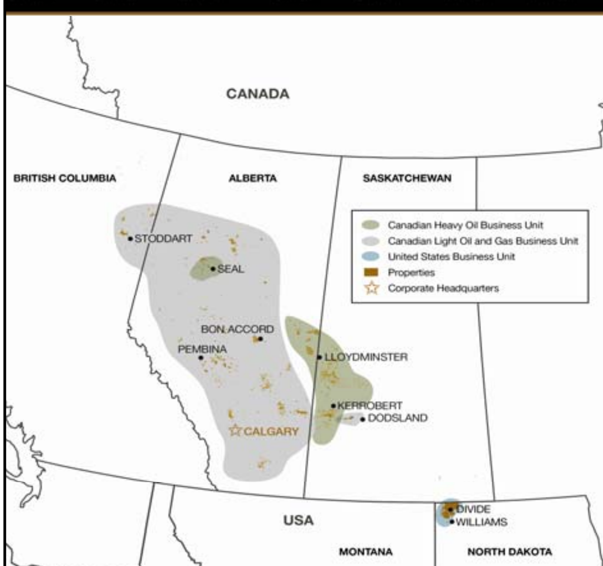
(1) Average daily trading volumes for January 1-30, 2012. Volumes are a composite of all exchanges in Canada and the U.S.
(2) The dividend yield is calculated by dividing the annualized dividend of C$2.64 by the closing price of Baytex shares of C$57.64 on the TSX on January 30, 2011.
(3) The US$180 million 9.625% Senior Subordinated Notes due July 15, 2010 were redeemed on September 25, 2009.

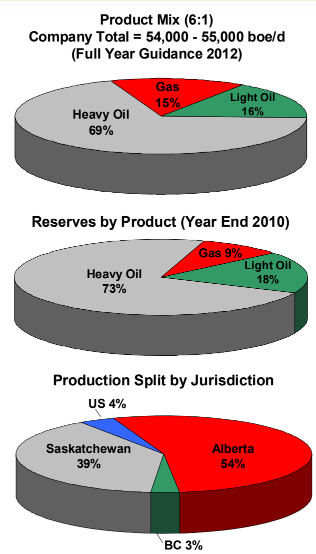
BAYTEX ENERGY CORP. — Management Ownership



Officers' share ownership is approximately 16x total annual salary as of January 30, 2012.

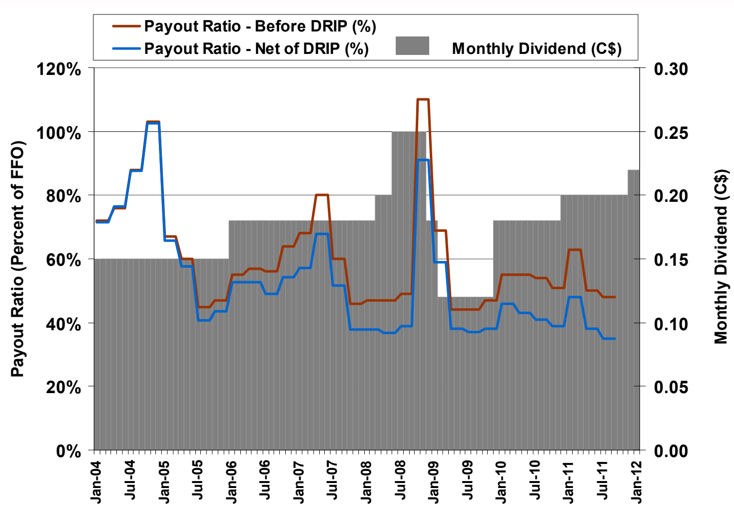
BAYTEX ENERGY CORP. — Operating Areas



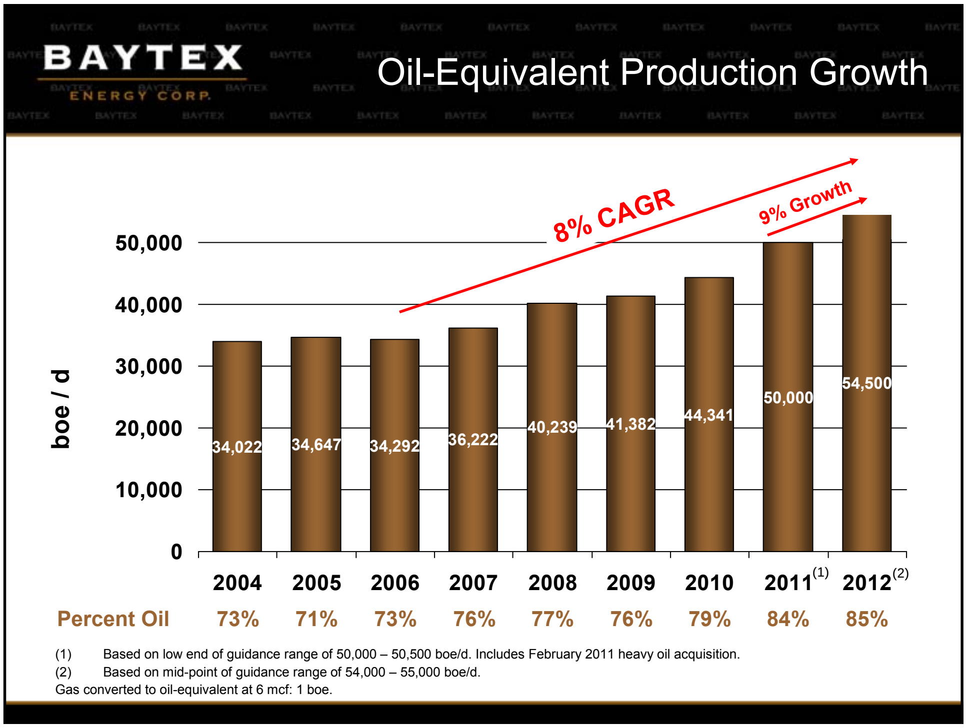


Historical Performance

Distribution / Dividend History



Note: In Q3 2011, DRIP participation rate was 28%.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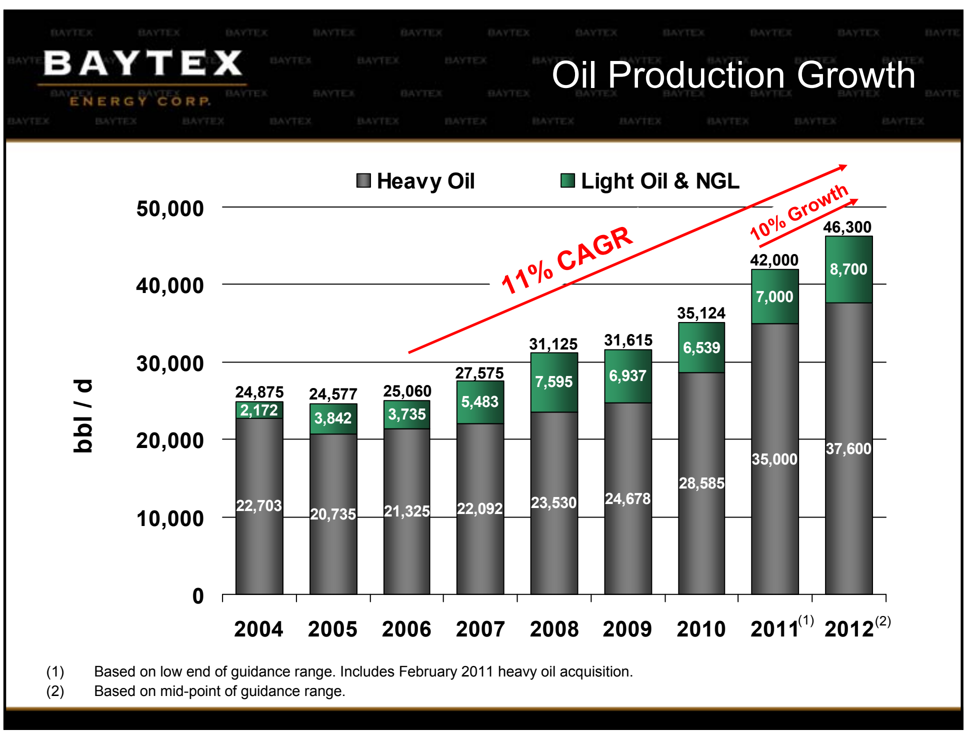
Oil-Equivalent Production Growth
8% CAGR
9% Growth
boe / d
50,000
40,000
30,000
20,000
10,000
0
34,022
34,647
34,292
36,222
40,239
41,382
44,341
50,000
54,500
2004 2005 2006 2007 2008 2009 2010 2011(1) 2012(2)
Percent Oil 73% 71% 73% 76% 77% 76% 79% 84% 85%
(1) Based on low end of guidance range of 50,000 – 50,500 boe/d. Includes February 2011 heavy oil acquisition.
(2) Based on mid-point of guidance range of 54,000 – 55,000 boe/d.
Gas converted to oil-equivalent at 6 mcf: 1 boe.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Oil Production Growth
Heavy Oil
Light Oil & NGL
11% CAGR
10% Growth
bbl / d
50,000
40,000
30,000
20,000
10,000
0
24,875 2,172 22,703
24,577 3,842 20,735
25,060 3,735 21,325
27,575 5,483 22,092
31,125 7,595 23,530
31,615 6,937 24,678
35,124 6,539 28,585
42,000 7,000 35,000
46,300 8,700 37,600
2004 2005 2006 2007 2008 2009 2010 2011(1) 2012(2)
(1) Based on low end of guidance range. Includes February 2011 heavy oil acquisition.
(2) Based on mid-point of guidance range.

Capital Program Efficiency

	2008	2009	2010	3-Year Average 2008-10	5-Year Average 2006-10	Trust Era 2004-10
FD&A Cost (P + P) (1)						
Excluding FDC (C$/boe)	13.11	11.63	5.90	9.54	9.59	**9.00**
Including FDC (C$/boe)	16.06	21.00	13.17	15.92	14.99	**13.61**
Recycle Ratio (P + P) (1)						
Excluding FDC	2.6	2.4	5.6	3.3	3.1	**3.0**
Including FDC	2.1	1.3	2.5	2.0	2.0	**2.0**
CAPEX as a % of FFO (2)						
Exploration & Development	43%	49%	52%	48%	49%	**51%**
Acquisitions	61%	40%	10%	37%	39%	**42%**
Total	104%	89%	62%	85%	88%	**93%**
Production Replacement (P+P)						
Exploration & Development	119%	113%	271%	170%	157%	**142%**
Acquisitions	114%	52%	26%	63%	68%	**84%**
Total	233%	165%	297%	233%	225%	**226%**

(1) Includes both E&D and acquisition CAPEX.

(2) Funds From Operations ("FFO") includes realized hedging gains / losses.

Reserves / Contingent Resources

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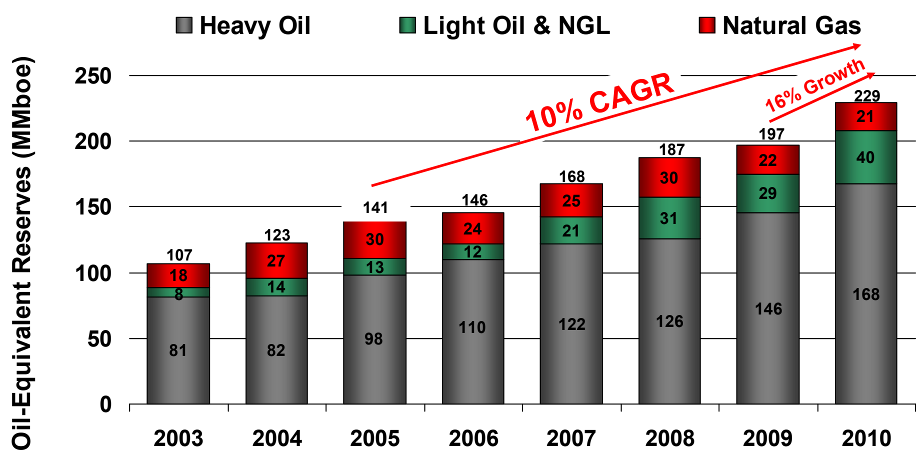
Oil-Equivalent Reserve Growth



Percent Oil	**83%**	**78%**	**79%**	**83%**	**85%**	**84%**	**89%**	**91%**

Proved plus probable working interest reserves per NI 51-101 as evaluated by Sproule Associates Limited.
Gas converted to oil-equivalent at 6 mcf: 1 boe.

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Contingent Resource Assessment (Recoverable Volumes From Three Resource Plays)

(millions of barrels of oil equivalent and bitumen) [1]	Contingent Resources [2] As at May 1, 2011 Low (C1) Estimate	Best (C2) Estimate	High (C3) Estimate
Bluesky – Seal, Alberta (excluding 2011 acquisition)	**478**	**583**	**846**
Bakken/Three Forks – Divide/Williams County, ND, USA	**59**	**138**	**254**
Viking			
Redwater, Alberta	6	12	23
Kerrobert/Whiteside, Saskatchewan [3]	3	6	12
Viking Total	**9**	**18**	**35**
Total	**546**	**739**	**1,135**
Percent Oil	**99%**	**98%**	**98%**

[1] Under National Instrument 51-101 "Standards of Disclosure for Oil and Gas Activities" of the Canadian Securities Administrators ("NI 51-101"), naturally occurring hydrocarbons with a viscosity greater than 10,000 centipoise are classed as bitumen. The majority of the contingent resource at Seal expected to be recovered by thermal processes has a viscosity greater than this value; therefore, this component of the contingent resource is classified as bitumen under NI 51-101.

[2] Sproule prepared the estimates of contingent resource shown for each property using deterministic principles and methods. Probabilistic aggregation of the low and high property estimates shown in the table might produce different total volumes than the arithmetic sums shown in the table.

[3] Contingent Resource Assessment for Saskatchewan Viking adjusted to reflect sale of Dodsland Viking lands, which closed on November 24, 2011.

See "Advisory – Oil and Gas Information" for more information about contingent resources.

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Long Range Plan

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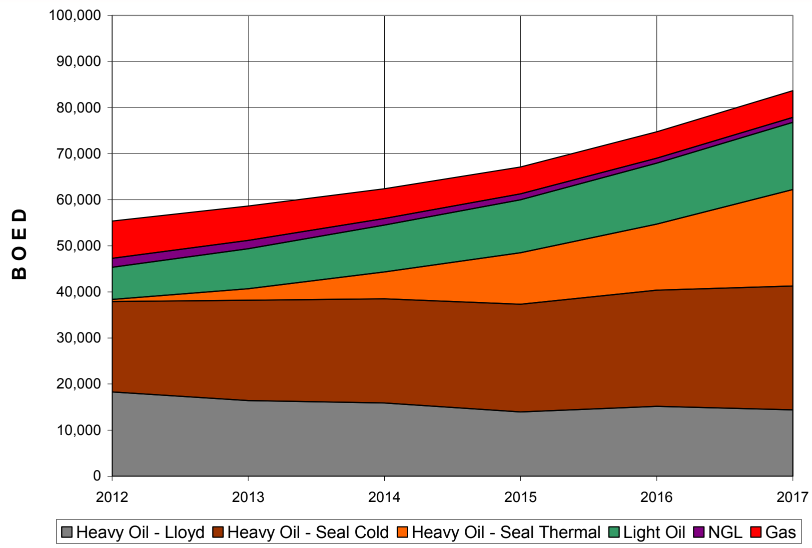
Long Range Plan - Construction

- **Long Range Plan = Internal well-by-well economic model of Baytex**
  - Projects all PDP wells individually
  - All organic development projects currently internally identified within existing land base, using existing technologies, are available to the model (not NI 51-101 compliant)
  - Projects budget year (2012) plus five "out-years" (2013-2017)
  - Income tax projections are based on current tax pools plus future additions from organic CAPEX program
  - Any future land or producing property acquisition will be incremental to Long Range Plan projection
- **Product price assumptions**
  - Commodity assumptions: $90 WTI oil, 15% WCS differential, $4 AECO gas and $1.00 Cdn/US FOREX
  - "Flat real" price deck – inflate product prices, CAPEX and OPEX at 2% per year after 2012
- **Net wells projected during 2012-2017 plan period**

Lloydminster	Cold Vertical = 210	Cold Horizontal = 285	Kerrobert SAGD = 7	
Seal	Cold = 285	Thermal = 185		
Western Cdn LO/Gas	Viking = 185	Cardium = 20	Other Oil = 25	Gas = 30
US	Bakken/Three Forks = 95			

Projected Organic Production Growth



Heavy Oil Projects

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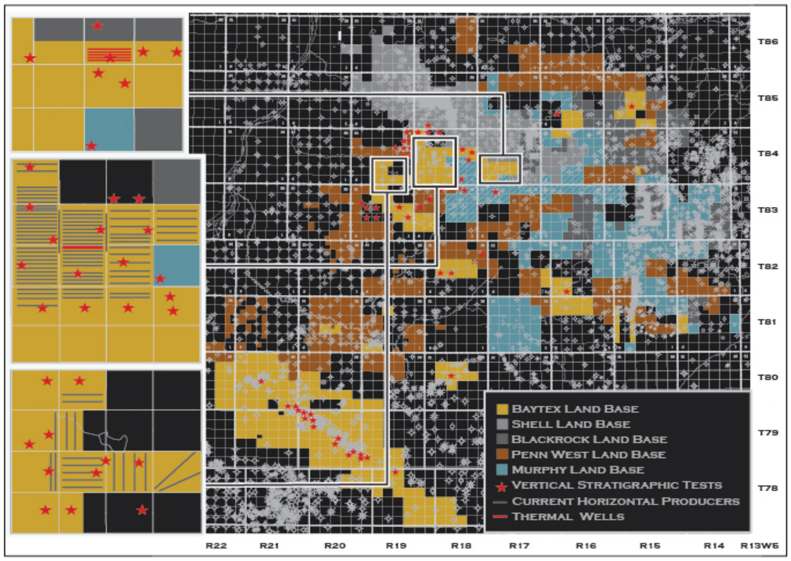
Seal – Heavy Oil Resource Play



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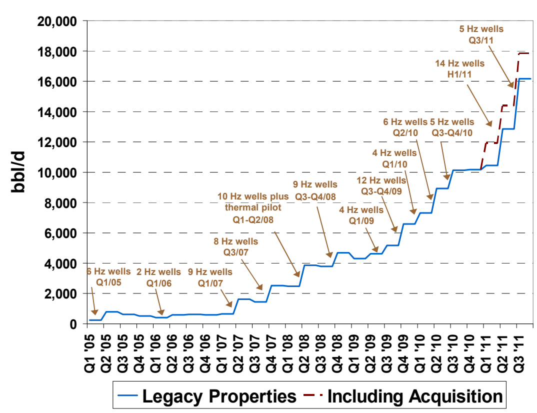
Seal – Primary Development

- **Land position**
  - **Crown Purchases 1999-2005**
    - 67,000 acres (105 sections) of 100% land
    - Estimated original oil in place (OOIP) per prospective section ≈ 50 million barrels
  - **February 2011 Acquisition**
    - 101,000 acres (158 sections) of 100% land
    - OOIP and prospectivity not fully delineated
- **Primary (cold) development**
  - Based on 8-lateral well design
  - CAPEX = $2.1 million/well
  - IP = 400 - 500 bbl/d per well
  - EUR = 490 Mbbl/well
  - Drill, complete and equip capital cost ≈ $4.30 per bbl
  - Recovery factor: 5-7% OOIP
- **Field average OPEX (9 months 2011)**
  - Legacy properties = $3.81 per bbl
  - February 2011 acquisition lands = $8.96 per bbl

Seal Production



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Seal – Multi-Lateral Cold Horizontal

	Total Wells	Number of Laterals							Total Laterals
		Single	Two	Three	Four	Six/Seven	Eight	> Eight [2]	
2004	2	2	---	---	---	---	---	---	2
2005	4	4	---	---	---	---	---	---	4
2006	2	2	---	---	---	---	---	---	2
2007	17	13	4	---	---	---	---	---	21
2008	19	---	18	1	---	---	---	---	39
2009	17	1	1	7	3	2	3	---	72
2010 [1]	14	---	1	---	---	1	10	2	111
9 Mths 2011	21	---	---	---	---	1	---	20	262
Total	96	22	24	8	3	4	13	22	513
Initial Rate (bbl/d)		160	230	300	390	400	450	575	
Capex per Well ($mlns)		$1.1	$1.3	$1.5	$1.7	$1.8	$2.1	$2.6	
Production Efficiency ($ per boe/d)		$6,900	$5,400	$5,000	$4,200	$4,500	$4,650	$4,500	

[1] Table excludes eight Hz re-entries (87 laterals) drilled in 2010 with average rates of 480 bbl/d.

[2] Current well design is 8 mile-long laterals along with several shorter laterals. Of the 22 wells drilled to date with greater than 8 laterals, the average # of laterals per well is 13.

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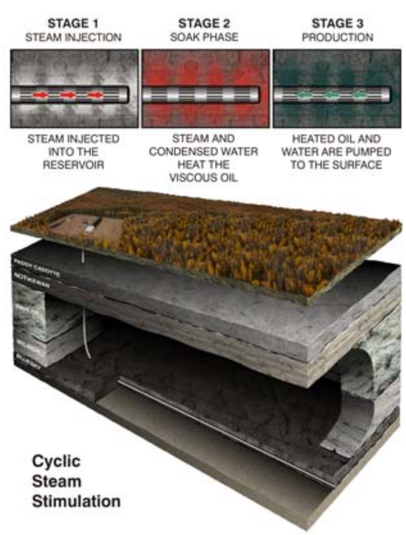
Seal – Thermal EOR Development

- **Modular development**
  - **Readily executable 10-well module size**
  - **Traditional oil and gas area with strong services presence and infrastructure**
  - **CAPEX = $31 million**
- **Recovery per 10-well module (Baytex estimates based on Cliffdale pilot)**
  - **Recovery factor ≈ 30% based on numerical reservoir simulation**
  - **Simulation validated by two field pilots**
  - **Oil rate = 1,900 bbl/d (peak year)**
  - **EUR = 4.7 MMbbl**
  - **Cumulative SOR = 2.9 BS/BO**
  - **OPEX using $4.00 per mcf gas cost = $14 per bbl**
  - **Unrisked pre-tax NPV_{10} based on $90 WTI / 15% WCS differential / $1 Cdn/US = approximately $9 per bbl, assuming immediate development timing**
- **Model based on 50 meter inter-well spacing (approximately 33 wells per section)**
- **Operation of first commercial module commenced in December 2011**



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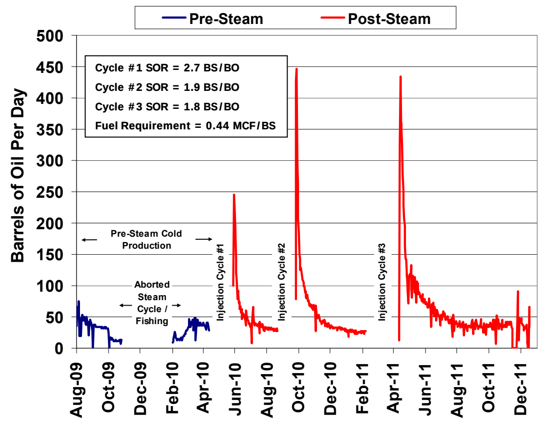
Seal – Cliffdale Thermal EOR Pilot

- **New development area**
  - Seven miles east of Harmon Valley
  - Not planned for large-scale cold development
  - Oil viscosity four times higher than in Harmon Valley pilot
  - Single-lateral horizontal well in lower part of Bluesky Sand
- **CSS pilot objectives**
  - Demonstrate injectivity into more viscous oil interval with little prior cold production
  - Multi-cycle test with injectivity, oil rate and SOR improvement
  - Validate numerical reservoir simulation to predict long-term performance
  - Achieve economic oil rate and SOR (weighted average SOR = 2.0)
- **Numerical reservoir simulation predicts further performance improvement in subsequent cycles**



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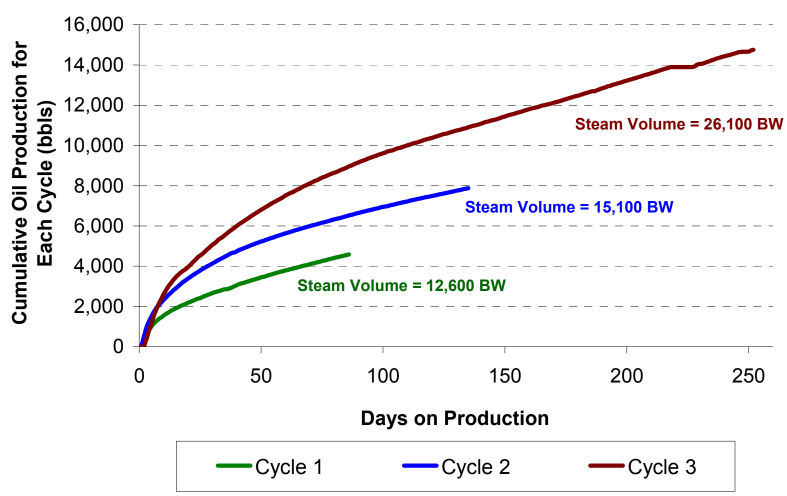
Seal – Cliffdale Thermal Pilot Cycle Progression



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Seal – Reserves Recognition

	Dec 31/05	Dec 31/06	Dec 31/07	Dec 31/08	Dec 31/09	Dec 31/10
Reserves (MMbbl)						
Total Proved	2.2	8.5	20.2	27.0	31.2	45.0
Proved plus Probable	4.0	13.0	28.7	39.2	54.7	83.9
Locations Assigned Reserves						
Proved Producing	6	8	25	44	60	77
Total Proved	14	62	103	106	137	167
Proved plus Probable	20	64	109	134	196	218
Land Assigned Reserves						
Sections (640 acres)	4	8	12	15	20	23

Notes: Proved volumes for 2010 include 5.1 MMbbls of thermally-enhanced oil recovery covering approximately one half section of land (20 locations). Proved plus probable volumes for 2010 include 30.3 MMbbls of thermally-enhanced oil recovery covering approximately 1.5 sections of land (60 locations). All other reserve volumes are for cold development.

Contingent Resource Assessment for Seal, prepared by Sproule Associates Limited as at May 1, 2011 = 478.3 MMboe of oil and bitumen (low estimate), 583.3 MMboe of oil and bitumen (best estimate) and 845.9 MMboe of oil and bitumen (high estimate). See "Advisory – Oil and Gas Information" for more information about contingent resources.

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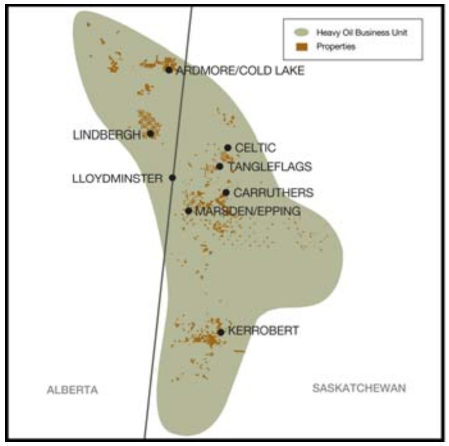
Seal – Low Environmental Impact

Baytex Seal Thermal Project
Non-Mining Oil Sands Development

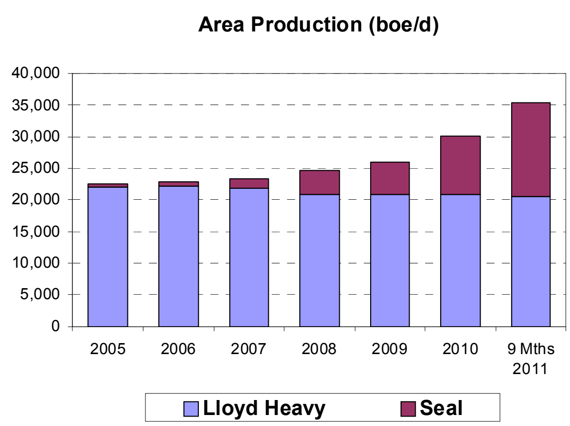
Lloydminster Heavy Oil

- 9 Months 2011 Production = 20,600 boe/d (42% of total Baytex volumes)
- Oil Gravity = 11 to 18 °API
- YE 2010 Reserves (2P) = 85 mmboe (37% of total Baytex reserves)
- Reserve Life Index (2P) = 11.2 years
- Land Position = 513,600 net acres
- 2010 Drilling: 67 gross (56.7 net) wells
  95% success rate
  40% horizontal wells
- 2011 E&D CAPEX: ≈ $90 million
- 2011 Drilling: ≈ 90 gross (85 net) wells
  ≈ 50% horizontal wells

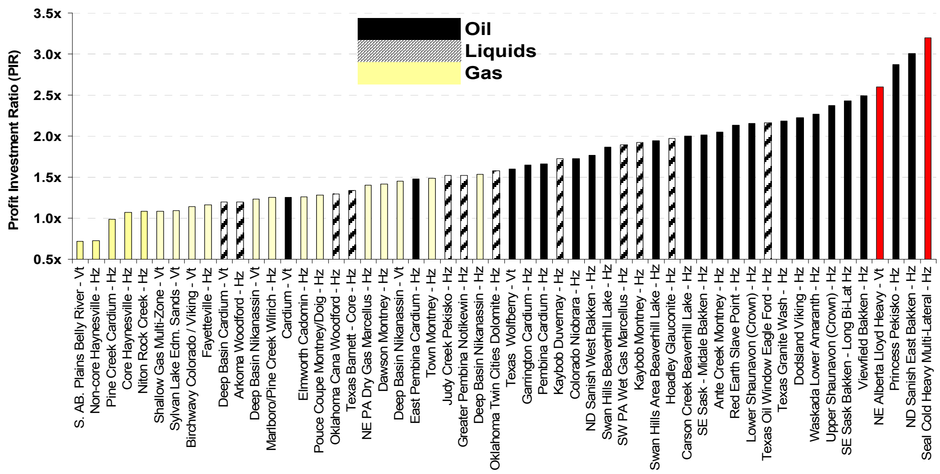


Lloydminster Drilling Inventory

- > 5 year drilling inventory
- Drilling inventory has increased by 75% over the past five years
- Development includes vertical & horizontal cold / waterflood / thermal (SAGD)
- Efficiency ratios (half cycle):
  - $12,100 per boe/d
  - $10.10/boe based on 2P reserves
- 2010 netback of $34.50/boe generates a recycle ratio of 3.4x



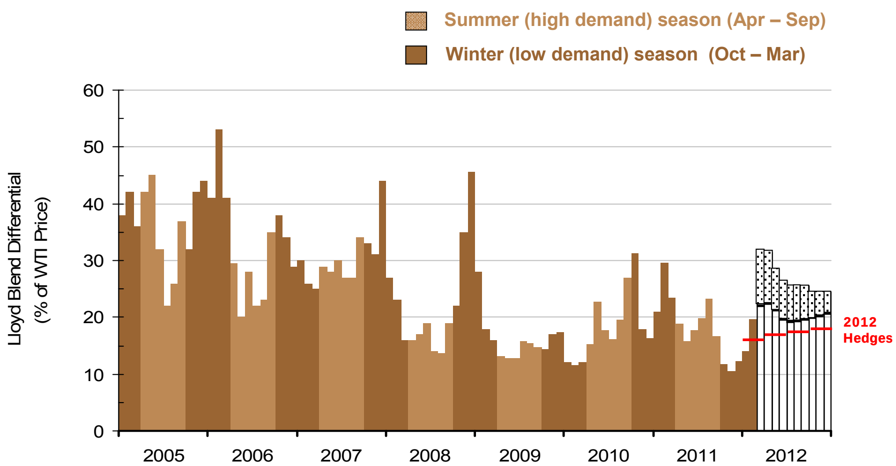
North America Resource Play Comparables



Source: Scotia Capital as at March 2011. Profit/Investment Ratio (PIR) defined as the present value of the future cash flows (after-tax, 9% discount rate) divided by the initial investment.
Commodity assumptions: WTI oil US$95.00/bbl, NYMEX gas US$5.00/mcf, heavy oil differential to Western Canadian Select 25%.

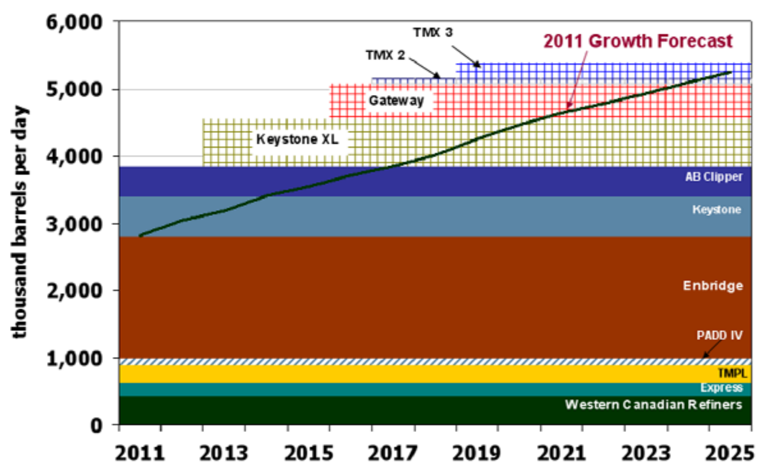
Heavy Oil Pricing

Heavy Oil Differential



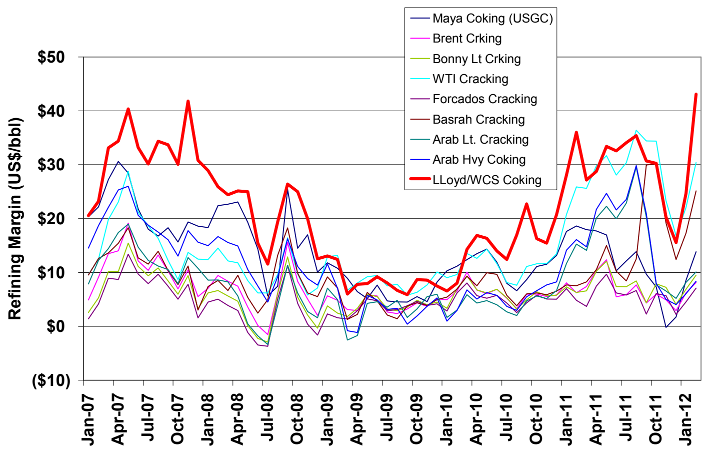
Note: February 2012 differential uses month-to-date WTI price as of February 9, 2012. Forward strip (shaded area) reflects change in the market from January 24, 2012 to February 9, 2012.

Midstream Heavy Oil Fundamentals – Pipeline Capacity vs. Crude Production



Source: Canadian Association of Petroleum Producers, June 2011.
Notes: Black lines represent Western Canadian crude supply including diluent volumes. Even though projected aggregate capacity volumes exceeds projected aggregate crude oil supply, transportation constraints could still develop to specific transportation destinations. In addition to the pipelines shown here, new pipelines may be built to access new markets such as the Pacific Rim.

Downstream Heavy Oil Fundamentals – Mid-Continent Refining Margins



Notes: Lloydminster coking margin shown through 2008; WCS coking margin used starting 2009. Mayan coking margins shown are for the U.S. Gulf Coast.
Source: Bloomberg.

Light Oil Projects

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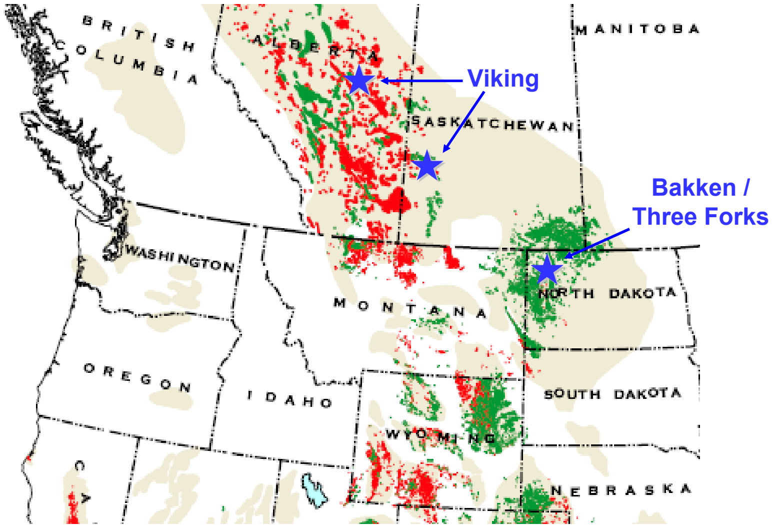
Light Oil Resource Plays



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Light Oil Resource Potential

	Initial Rate [1] (Boe/d / well)	Estimated Recovery [1] (Mboe/well)	Well Cost [1] ($Mln/well)	Potential Net Locations [1]	Contingent Resource [2] (millions of barrels of oil) Low (C1) Estimate	Best (C2) Estimate	High (C3) Estimate
Bakken / Three Forks [3]	420	420	US$6.1	100 - 300	59.2	138.1	253.8
Viking (AB) [4]	110	100	C$2.0	105	5.4	11.3	22.7
Viking (SK) [4]	50	50	C$1.1	100	2.8	5.9	12.2
Total					67.4	155.3	288.7

(1) Initial 30-day rate, estimated recovery per well, well cost, and potential net locations all reflect Baytex internal estimates.

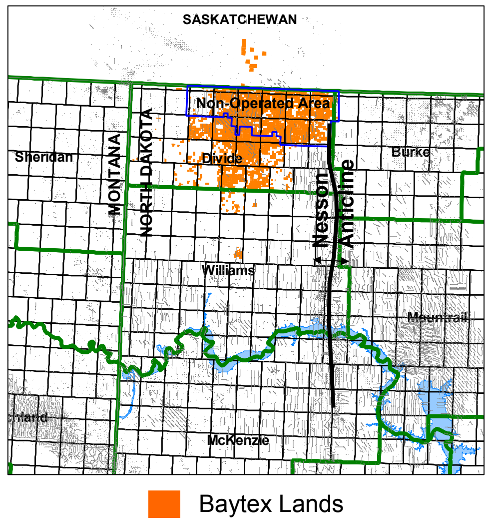
(2) Contingent Resource Assessment prepared by Sproule Associates Limited as at May 1, 2011. Contingent Resource Assessment for Saskatchewan Viking adjusted November 2011 to reflect sale of Dodsland Viking lands. See "Advisory – Oil and Gas Information" for more information about contingent resources.

(3) Bakken-Three Forks initial rate and EUR based on 1280-acre well (two-mile long) performance. Potential net locations based on spacing of 1 to 3 wells per 2-section drilling spacing unit (DSU).

(4) Alberta Viking uses unfrac'd multi-lateral wells; well cost based on mile-long horizontal wells. Saskatchewan Viking uses frac'd single lateral wells.

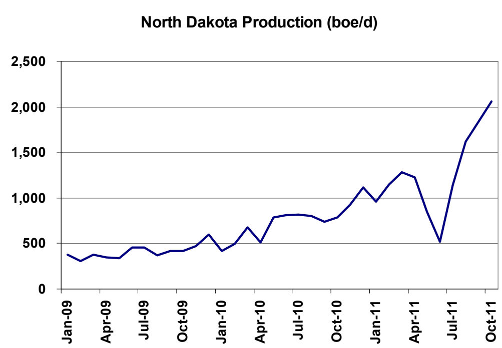
Bakken / Three Forks Land Position

- Approximately 130,000 net acres in Bakken / Three Forks Play
- 95% of net acreage is in North Dakota / 5% is in SE Saskatchewan
- Majority of acreage expected to be Baytex-operated
- Majority of current production is Baytex-operated



Bakken / Three Forks Light Oil Development

- Current development predominantly in the Three Forks formation
- Additional potential to develop Middle Bakken
- 180-square mile 3D to guide Bakken/Three Forks resource play development and identify conventional exploration targets
- Initially 1-mile long (640 acre) wells → now largely shifted to 2-mile long (1280 acre) wells
- Evolution of frac staging: initially 6 stages/well → now 20 stages/well → evaluating 30 stages/well RapidFrac™
- ≈ 10 net wells planned for 2011



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Hedging

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Oil Hedge Coverage

		2012	2013	2014
WTI Crude Oil				
% of Crude Oil Volumes Hedged [1]				
Fixed Price	***2012 average:*** US$96.80/bbl	32%	0%	0%
Costless Collars	***2012 Floor-Ceiling Range:*** *US$97.50/bbl - US$105.92/bbl)* [2]	3%	0%	0%
		35%	0%	0%
Heavy Oil Differentials				
% of Heavy Oil Volumes Hedged [1]		22%	19%	5%
Equivalent Fixed Differential to WTI (US$/bbl)		17.01	19.56	16.10
Equivalent Percent Differential, % of WTI		16.8%	19.3%	16.5%

*(equivalent differentials using WTI prices: **2012:** US$102.01/bbl, **2013:** US$101.64/bbl, **2014:** US$97.82/bbl)*

[1] Percentage of 2012 volumes hedged are based on 54,500 boe/d (mid-point of company guidance), net of royalties (i.e., hedgeable volumes).

[2] Average WTI collar range: **2012:** US$98.92/bbl (floor) and US$104.92/bbl (ceiling). See notes to financial statements for individual collar contracts.

Other Commodities / FOREX Hedge Coverage

		2012	2013	2014
Natural Gas				
% of Natural Gas Volumes Hedged [1]				
Fixed Price	***Average Price: 2012:*** C$4.39/mcf	18%	0%	0%
Sold Calls	***Average Strike/Premium:***			
	2012: US$5.25/mmbtu/ US$0.48/mmbtu	16%	0%	0%
Total Natural Gas		34%	0%	0%
Condensate Purchases				
% of Condensate Requirement Purchased		10%	3%	0%
Equivalent Premium (Discount) to WTI (US$/bbl)		6.70	6.70	
Foreign Exchange				
% of Foreign Exchange Hedged		28%	9%	0%
Hedged Amount (US$ millions)		229	70	0
Average Swap Rate (CAD per USD)		1.0233	1.0075	-

[1] Percentage of 2012 volumes hedged are based on 54,500 boe/d (mid-point of company guidance), net of royalties (i.e., hedgeable volumes).

Balance Sheet

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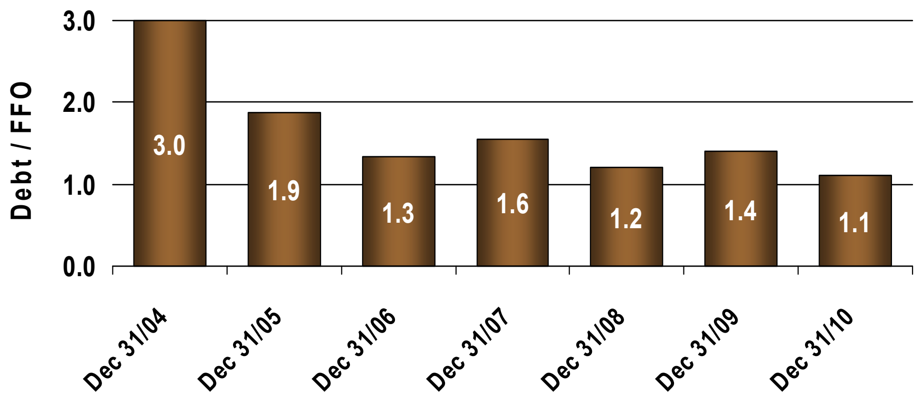
Balance Sheet Improvement



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Credit Metrics

	Dec 31 2004	Dec 31 2005	Dec 31 2006	Dec 31 2007	Dec 31 2008	Dec 31 2009	Dec 31 2010	Sept 30 2011
Credit Facility (C$ Millions)								
Approved credit facility	250	250	300	370	485	515	550	700
Bank line undrawn	89	127	173	128	277	250	246	332
Debt to EBITDA	2.6	1.5	1.2	1.4	1.0	1.3	1.1	1.1[1]
Debt to Funds From Operations	3.0	1.9	1.3	1.6	1.2	1.4	1.1	1.4[1]
Interest Coverage Ratio	8.4	8.6	8.8	9.1	16.6	11.1	17.0	15.5[1]
Debt / Reserves ($/boe)								
Proved	4.89	4.18	3.58	3.83	4.24	3.67	3.92	4.96[2]
Proved + Probable	3.45	3.03	2.53	2.64	2.85	2.41	2.40	3.06[2]
Debt / Enterprise Value	33%	26%	18%	22%	27%	13%	9%	13%

(1) 12 month trailing, including pro forma 12 month contribution from assets acquired in H1 2011.
(2) Includes reserve volumes acquired in the first three quarters of 2011.

Tax Treatment of Dividends

Tax Treatment of Dividends – US Recipients

Type of Recipient	Canadian withholding tax rate	Is dividend taxable to recipient in country of receipt?	Is Foreign Tax Credit available for Cdn w/h tax? [3]	Is refund available for excess Cdn w/h tax? [4]
Individual - taxable account	15%	Yes (as a qualifying dividend)	Yes	NA
Individual – tax exempt account (e.g. IRA or 401k)	0% [1]	No [2]	NA	Yes
Corporate	15%	Yes	Yes	NA
Tax Exempt (e.g. pension or endowment fund)	0% [1]	No	NA	Yes

(1) Tax Exempts must provide evidence of exempt status to avoid withholding tax. If tax is withheld, it can recovered later with appropriate documentation. Please consult your tax advisor.
(2) Taxable at withdrawal. Please consult your tax advisor.
(3) The annual claim for foreign tax credits may be limited by US Alternative Minimum Tax.
(4) Refers to cases in which documentation of tax exempt status is provided to tax authority after Canadian withholding. Please consult your tax advisor.

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Relative Performance / Valuation

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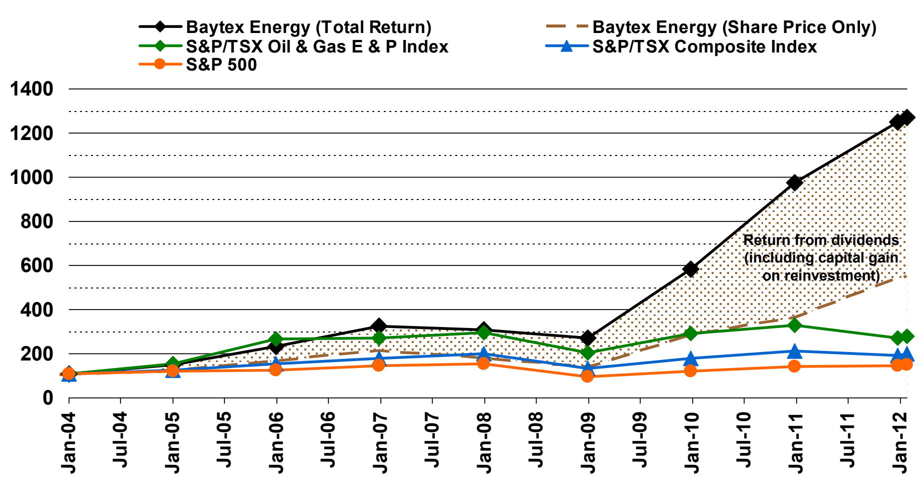
Total Return Performance



Source: TSX Historical Data, Bloomberg Data, and Company information. Total return includes capital appreciation, cash distributions/dividends and reinvestment of distributions/dividends to January 30, 2012.

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Value Comparison to Oil-Weighted Canadian Corporations

	Baytex	EV-Weighted Group Average *(Range)*
EV / Production (C$/boe/d)	**$137,200**	**$158,700** *($37,000 – $327,900)*
EV + FDC / P+P Reserves (C$/boe)	**$38.28**	**$38.62** *($4.50 – $378.05)*
EV/DACF 2012(e)	**10.1x**	**10.3x** *(4.9x – 20.9x)*
Debt / CF 2012(e)	**0.7x**	**1.8x** *(0.0x – 4.5x)*
Yield 2011(e)	**4.6%**	**4.2%** *(0.0% – 7.5%)*
Oil Weighting	**85%**	**83%** *(65% – 100%)*

Source: Scotia Capital research as at January 30, 2012. Comparison group is Scotia Capital's Canadian oil-weighted producers group and includes Baytex, BlackPearl, Bonterra, Crescent Point, Legacy, Longview, MEG, Penn West, PetroBakken, Pinecrest, Rock, Vermilion and Wild Stream (all intermediate and junior producers > 65% oil weighting). Scotia is currently on restriction for Penn West. Average is based on enterprise value weighting. In calculating EV/P+P Reserves, Scotia Capital includes future development costs ("FDC") in the enterprise value.

2012 Commodity assumptions: WTI oil US$95.00/bbl, Nymex gas US$4.00/mmbtu, US$0.98/Cdn$, heavy oil differential 18%.

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