BAYTEX
ENERGY CORP.

BAYTEX REPORTS RECORD PRODUCTION AND FUNDS FROM OPERATIONS AND STRONG RESERVES GROWTH FOR 2014

CALGARY, ALBERTA (March 5, 2015) - Baytex Energy Corp. ("Baytex")(TSX, NYSE: BTE) reports its operating and financial results for the three months and year ended December 31, 2014 (all amounts are in Canadian dollars unless otherwise noted).

“Our 2014 results reflect the continued strong performance of our Canadian assets and the significant growth in assets associated with our Eagle Ford acquisition. The addition of the Eagle Ford to our portfolio has provided us with exposure to one of the premier oil resource plays in North America and has enhanced the quality of our reserves base. The Eagle Ford generates the strongest capital efficiencies in our development inventory, provides the highest cash netbacks and has a significant and growing inventory of development prospects,” commented James Bowzer, President and Chief Executive Officer.

Bowzer said, “The current commodity price environment remains challenging and we will continue to prudently manage our business in order to preserve financial flexibility. In 2015, we anticipate investing $500 to $575 million in exploration and development activities, approximately 80% of which will be directed to the Eagle Ford. We remain focused on creating long-term value for our shareholders through our growth and income business model.”

Highlights

- Generated production of 92,220 boe/d (85% oil and NGL) during Q4/2014, an increase of 53% over Q4/2013, and 78,321 boe/d for full-year 2014, an increase of 37% over 2013;

- Exceeded the high end of our second half 2014 production guidance by 6% as set out on closing of the Eagle Ford acquisition in June 2014 and by 1% as revised upward in November 2014;

- Delivered funds from operations ("FFO") of $245.5 million ($1.47 per share) in Q4/2014, an increase of 66% over Q4/2013, and $879.8 million ($5.91 per share) in full-year 2014, an increase of 46% over 2013 and the highest level of annual FFO in company history;

- Produced 38,051 boe/d (82% oil and NGL) in the Eagle Ford during Q4/2014, an increase of 12% over Q3/2014 and 37% from the time of the acquisition;

- Increased proved reserves by 78% to 283 million boe (an increase of 33% on a per share basis) and proved plus probable reserves by 36% to 432 million boe (an increase of 2% on a per share basis). Proved reserves represent 66% of proved plus probable reserves (up from 50% at year-end 2013);

- Increased reserves in the Eagle Ford from the time of the acquisition by 57% on proved reserves and 13% on proved plus probable reserves, and recognized an incremental 220 million boe of possible reserves;

- Replaced 118% of production through exploration and development activities and 497% of production inclusive of acquisitions and divestitures;

- Recorded finding and development (“F&D”) costs for proved plus probable reserves, including changes in future development costs, of $19.77/boe for 2014; excluding our thermal projects, F&D costs were $11.71/boe generating a recycle ratio (operating netback divided by F&D costs) of 3.1x; and

- Divested certain non-core assets in Canada in Q4/2014 with associated production of approximately 1,250 boe/d (53% natural gas) for net proceeds of $45.7 million.

	Three Months Ended			Years Ended	
	December 31, 2014	September 30, 2014	December 31, 2013	**December 31, 2014**	December 31, 2013
FINANCIAL *(thousands of Canadian dollars, except per common share amounts)*					
Petroleum and natural gas sales	**$ 472,390**	$ 634,415	$ 330,712	**$ 1,969,022**	$ 1,367,459
Funds from operations (1)	**245,513**	297,964	147,544	**879,790**	604,438
Per share - basic	**1.47**	1.79	1.18	**5.91**	4.88
Per share - diluted	**1.47**	1.78	1.17	**5.91**	4.82
Cash dividends declared (2)	**72,509**	89,771	59,532	**301,118**	237,663
Dividends declared per share	**0.58**	0.72	0.66	**2.64**	2.64
Net income (loss)	**(361,816)**	144,369	31,173	**(132,807)**	164,845
Per share - basic	**(2.16)**	0.87	0.26	**(0.89)**	1.33
Per share - diluted	**(2.16)**	0.86	0.25	**(0.89)**	1.32
Exploration and development	**214,697**	230,032	85,060	**766,070**	550,900
Acquisitions, net of divestitures	**(35,666)**	(341,908)	2,258	**2,545,156**	(39,082)
Total oil and natural gas capital expenditures	**$ 179,031**	$ (111,876)	$ 87,318	**$ 3,311,226**	$ 511,818
Bank loan (3)	**$ 666,886**	$ 624,067	$ 223,371	**$ 666,886**	$ 223,371
Long-term debt (3)	**1,418,685**	1,380,811	459,540	**1,418,685**	459,540
Working capital deficiency	**210,409**	250,939	79,151	**210,409**	79,151
Total monetary debt (4)	**$ 2,295,980**	$ 2,255,817	$ 762,062	**$ 2,295,980**	$ 762,062

	Three Months Ended			Years Ended	
	December 31, 2014	September 30, 2014	December 31, 2013	**December 31, 2014**	December 31, 2013
OPERATING					
Daily production					
Heavy oil (bbl/d)	**43,135**	45,456	43,254	**44,948**	42,064
Light oil and condensate (bbl/d)	**26,916**	28,124	6,027	**17,681**	6,309
NGL (bbl/d)	**8,098**	6,629	2,020	**4,819**	1,825
Total oil and NGL (bbl/d)	**78,149**	80,209	51,301	**67,448**	50,198
Natural gas (mcf/d)	**84,428**	83,300	42,018	**65,234**	41,989
Oil equivalent (boe/d @ 6:1) (5)	**92,220**	94,093	60,184	**78,321**	57,195
Average prices (before hedging)					
WTI oil (US$/bbl)	**73.14**	97.17	97.46	**92.97**	97.97
WCS Heavy Oil (US$/bbl)	**58.90**	76.99	65.26	**73.58**	72.78
Edmonton par oil ($/bbl)	**75.69**	98.65	86.25	**95.28**	93.24
LLS oil (US$/bbl)	**76.34**	100.87	101.00	**96.76**	107.41
BTE heavy oil ($/bbl) (6)	**53.34**	73.99	61.89	**69.64**	65.24
BTE light oil and condensate ($/bbl)	**77.20**	99.65	84.35	**91.37**	90.31
BTE NGL ($/bbl)	**28.07**	36.77	46.01	**35.28**	42.63
BTE total oil and NGL ($/bbl)	**58.93**	79.91	63.91	**72.88**	67.57
BTE natural gas ($/mcf)	**4.12**	4.43	3.52	**4.53**	3.32
BTE oil equivalent ($/boe)	**53.72**	72.04	58.75	**66.54**	61.74
CAD/USD noon rate at period end	**1.1601**	1.1208	1.0636	**1.1601**	1.0636
CAD/USD average rate for period	**1.1378**	1.0893	1.0494	**1.1050**	1.0299

	Three Months Ended			Years Ended	
	December 31, 2014	September 30, 2014	December 31, 2013	**December 31, 2014**	December 31, 2013
COMMON SHARE INFORMATION					
TSX					
Share price (Cdn$)					
High	**42.90**	49.49	44.26	**49.88**	47.60
Low	**14.56**	41.73	40.21	**14.56**	36.37
Close	**19.32**	42.35	41.64	**19.32**	41.64
Volume traded (thousands)	**133,365**	40,645	22,585	**273,743**	105,097
NYSE					
Share price (US$)					
High	**38.35**	46.46	42.84	**46.46**	47.47
Low	**12.63**	37.54	37.78	**12.63**	34.75
Close	**16.61**	37.86	39.16	**16.61**	39.16
Volume traded (thousands)	**20,255**	5,212	3,657	**33,170**	15,071
Common shares outstanding (thousands)	**168,107**	166,709	125,392	**168,107**	125,392

Notes:

(1) Funds from operations is not a measurement based on generally accepted accounting principles ("GAAP") in Canada, but is a financial term commonly used in the oil and gas industry. We define funds from operations as cash flow from operating activities adjusted for finance costs, changes in non-cash operating working capital and other operating items. Baytex's funds from operations may not be comparable to other issuers. Baytex considers funds from operations a key measure of performance as it demonstrates its ability to generate the cash flow necessary to fund future dividends and capital investments. For a reconciliation of funds from operations to cash flow from operating activities, see Management's Discussion and Analysis of the operating and financial results for the year ended December 31, 2014.

(2) Cash dividends declared are net of participation in our Dividend Reinvestment Plan.

(3) Principal amount of instruments.

(4) Total monetary debt is a non-GAAP measure which we define to be the sum of monetary working capital (which is current assets less current liabilities (excluding non-cash items such as unrealized gains or losses on financial derivatives, assets held for sale and liabilities related to assets held for sale)), the principal amount of long-term debt and long-term bank loan.

(5) Barrel of oil equivalent ("boe") amounts have been calculated using a conversion rate of six thousand cubic feet of natural gas to one barrel of oil. The use of boe amounts may be misleading, particularly if used in isolation. A boe conversion ratio of six thousand cubic feet of natural gas to one barrel of oil is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

(6) Heavy oil prices exclude condensate blending.

Operations Review

Despite the challenging oil price environment in late 2014, we continue to achieve strong operating results across our core assets in Canada and the Eagle Ford. Production averaged 92,220 boe/d (85% oil and NGL) during Q4/2014, an increase of 53% over Q4/2013, and 78,321 boe/d for the full-year in 2014, an increase of 37% over 2013. Production in the second half of 2014 averaged approximately 93,200 boe/d, 6% above the high-end of our original production guidance range as set out on closing of the Eagle Ford acquisition in June 2014 and 1% above the high-end of our production guidance range as revised upward in November 2014.

Capital expenditures for exploration and development activities totaled $214.7 million in Q4/2014 and $766.1 million for full-year 2014. Full-year capital expenditures of $766 million came in at the low end of our guidance range of $765 to $790 million. In 2014, we participated in the drilling of 403 (216.6 net) wells with a 99% success rate.

Our 2015 production guidance remains at 84,000 to 88,000 boe/d with budgeted exploration and development expenditures of $500 to $575 million. Our guidance includes approximately 2,000 boe/d of uneconomic production that has been shut-in. We expect our production to be approximately evenly split between Canada and the Eagle Ford. Our production mix is forecast to be approximately 82% liquids (40% heavy oil, 33% light oil and condensate and 9% natural gas liquids) and 18% natural gas, based on a 6:1 natural gas-to-oil equivalency.

Approximately 80% of our 2015 capital budget will be invested in our Eagle Ford operations where we expect to drill 39 to 45 net wells. The remaining 20% will be invested in our heavy oil operations at Peace River and Lloydminster. Our budget for Canada will see approximately 70% of planned expenditures occurring in the second half of the year.

Wells Drilled - Three Months Ended December 31, 2014

	Crude Oil						Stratigraphic		Dry and			
	Primary		Thermal		Natural Gas		and Service		Abandoned		Total	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Heavy oil												
Lloydminster	24	5.1	—	—	—	—	—	—	1	0.2	25	5.3
Peace River	5	5.0	—	—	—	—	—	—	—	—	5	5.0
	29	**10.1**	**—**	**—**	**—**	**—**	**—**	**—**	**1**	**0.2**	**30**	**10.3**
Light oil and natural gas												
Eagle Ford	34	8.3	—	—	23	7.1	1	0.3	3	0.8	61	16.5
Western Canada	—	—	—	—	1	1.0	—	—	—	—	1	1.0
	34	**8.3**	**—**	**—**	**24**	**8.1**	**1**	**0.3**	**3**	**0.8**	**62**	**17.5**
Total	**63**	**18.4**	**—**	**—**	**24**	**8.1**	**1**	**0.3**	**4**	**1.0**	**92**	**27.8**

Wells Drilled – Twelve Months Ended December 31, 2014

	Crude Oil						Stratigraphic		Dry and			
	Primary		Thermal		Natural Gas		and Service		Abandoned		Total	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Heavy oil												
Lloydminster	170	90.0	2	2.0	—	—	17	17.0	4	2.4	193	111.4
Peace River	31	31.0	—	—	—	—	24	24.0	—	—	55	55.0
	201	**121.0**	**2**	**2.0**	**—**	**—**	**41**	**41.0**	**4**	**2.4**	**248**	**166.4**
Light oil and natural gas												
Eagle Ford	69	17.5	—	—	59	15.7	1	0.3	3	0.8	132	34.3
Western Canada	6	5.7	—	—	3	3.0	—	—	—	—	9	8.7
North Dakota	14	7.2	—	—	—	—	—	—	—	—	14	7.2
	89	**30.4**	**—**	**—**	**62**	**18.7**	**1**	**0.3**	**3**	**0.8**	**155**	**50.2**
Total	**290**	**151.4**	**2**	**2.0**	**62**	**18.7**	**42**	**41.3**	**7**	**3.2**	**403**	**216.6**

U.S. Operations

Production in the Eagle Ford averaged 38,051 boe/d (82% oil and NGL) during Q4/2014, an increase of 12% over Q3/2014 and 37% from the time of the acquisition. Production from the Eagle Ford represented 41% of our Q4/2014 production.

Drilling results in the Eagle Ford have exceeded our initial expectations with wells drilled in 2014 outperforming the type curves used in our acquisition evaluation. The evaluation was based on 30-day initial production rates of 800 to 1,000 boe/d. Since acquisition, a total of 128 (32.2 net) wells have been placed on production in 2014 with average 30-day initial production rates of 1,000 to 1,200 boe/d, representing an approximate 22% improvement. This improved performance is driven by a combination of factors, including the drilling of longer horizontal laterals, tighter spacing of fracs and an increased amount of proppant per frac stage. These individual well economics provide some of the highest capital efficiencies in North America.

In Q4/2014, we participated in the drilling of 57 (15.4 net) wells and commenced production from 64 (15.3 net) wells. The capital expenditures for the Eagle Ford assets in Q4/2014 totaled $149.5 million.

We have also identified additional well locations to support future growth. In addition to targeting the Lower Eagle Ford formation, we are now actively delineating the Austin Chalk formation. To-date, we have delineated the Austin Chalk on over 50% of our acreage. Since acquisition, we have drilled 14 (4.0 net) Austin Chalk horizontal wells and brought 12 (3.3 net) on production. These 12 wells had an average 30-day initial production rate of 1,050 boe/d. As of year-end, the Austin Chalk has 19 (5.4 net) producing wells.

We have entered into a new phase of the development of the Eagle Ford with the initiation of “stack and frac” pilots which target three zones in the Eagle Ford formation in addition to the overlying Austin Chalk. Results of these pilots are expected in 2015.

Canadian Operations

Production in Canada averaged 54,185 boe/d (87% oil and NGL) during Q4/2014, a decrease of 1% over Q4/2013, and 56,183 boe/d for full-year 2014, an increase of 4% over 2013. Production from Canada represented 59% of our Q4/2014 production.

Production from our Peace River area properties averaged approximately 25,700 boe/d in Q4/2014, slightly lower than our Q3/2014 production of 26,500 boe/d. In Q4/2014, we drilled five (5.0 net) cold horizontal producers in the Peace River area. In 2015, our capital budget includes the drilling of approximately 8 net horizontal multi-lateral wells and 8 to 12 stratigraphic and service wells.

We also completed the construction of surface facilities for our water flood pilot in the Bluesky reservoir in Harmon Valley. Water injection commenced in early Q1/2015. This is our first water flood project in the Peace River area, which, if successful, could enhance our ultimate recoveries from the field.

Subsequent to the end of 2014, we announced the completion of the first phase and commissioning of Genalta Power’s Peace River Power Centre. This new facility is located near our Three Creeks field and is designed to conserve solution gas while providing low emission electricity into Alberta’s power grid. The second phase of this project is anticipated to be commissioned in mid-2015 and will further increase the conservation of our solution gas in the region.

At Lloydminster, we participated in drilling 25 (5.3 net) oil wells during Q4/2014 and we observed the production response to a water flood project that was commissioned in the third quarter in the Lloydminster formation. Crude oil production is currently 300% higher than immediately prior to the commencement of water injection. We continue to monitor the performance of this project and are evaluating our portfolio for similar opportunities. In 2015, our capital budget includes the drilling of approximately 26 net development wells, of which approximately 80% will be horizontal wells.

In late 2014, we disposed of certain non-core assets in Canada with associated production of approximately 1,250 boe/d (53% natural gas). Net proceeds of $45.7 million were applied against outstanding indebtedness.

Financial Review

We generated FFO of $245.5 million ($1.47 per share) during Q4/2014, representing a decrease of 18% from Q3/2014 and an increase of 66% from Q4/2013. Full-year FFO was $879.8 million ($5.91 per share), an increase of 46% compared to 2013 and established a new company record for annual FFO. This increase was largely due to higher sales volumes resulting from the Eagle Ford acquisition and higher realized commodity prices.

Our Q4/2014 financial results were impacted by the decline in crude oil prices in late 2014. The average price for West Texas Intermediate (“WTI”) for Q4/2014 was US$73.14/bbl, representing a decrease of 25% from both Q3/2014 and Q4/2013. The discount for Canadian heavy oil, as measured by the Western Canadian Select ("WCS") price differential to WTI, averaged 20% in Q4/2014, as compared to 21% in Q3/2014 and 33% in Q4/2013. Our realized oil and NGL price of $58.93/bbl in Q4/2014 decreased by 26% from $79.91/bbl in Q3/2014 and 8% from $63.91/bbl in Q4/2013.

Due to the significant decline in commodity prices, the estimated future cash flows of certain assets dropped below the carrying value of those assets. As a result, we recorded a goodwill impairment charge of $449.6 million in Q4/2014, including $411.8 million related to goodwill associated with the Eagle Ford acquisition and $37.8 million related to goodwill associated with certain conventional oil and gas assets in Canada. No impairment was recorded on our heavy oil assets. Primarily as a result of the impairment, we incurred a net loss of $132.8 million ($0.89 per share) in 2014, as compared to net income of $164.8 million ($1.33 per share) in 2013.

We generated an operating netback in Q4/2014 of $26.80/boe excluding financial derivatives and $33.28/boe including financial derivatives. Our Canadian operations generated an operating netback of $23.45/boe while the Eagle Ford generated an operating netback of $31.58/boe. Our Eagle Ford assets are located in south Texas and are proximal to Gulf Coast crude oil markets with established transportation systems, resulting in strong realized prices. Our light oil and condensate production in the Eagle Ford is priced primarily off a Louisiana Light Sweet (LLS) benchmark which typically trades at a premium to WTI. This strong pricing, combined with low cash costs, contributed positively to our operating netback in Q4/2014. The table below provides a summary of our operating netbacks for the periods noted.

	Three Months Ended Dec. 31, 2014			Three Months Ended	
($ per boe)	**Canada**	**Eagle Ford**	**Total**	**Dec. 31, 2013**	**Change**
Sales Price	$49.66	$59.50	$53.72	$58.75	(9) %
Less:					
Royalties	7.94	17.56	11.90	11.49	4 %
Production and operating expenses	14.76 (1)	10.36 (2)	12.95	12.87	1 %
Transportation expenses	3.51	—	2.07	3.94	(47) %
Operating netback	$23.45	$31.58	$26.80	$30.45	(12) %
Financial derivatives gain	—	—	6.48	1.03	529 %
Operating netback after financial derivatives	$23.45	$31.58	$33.28	$31.48	6 %

(1) Full-year 2014 production and operating expenses in Canada averaged $13.27/boe ($12.89/boe in 2013).
(2) In the Eagle Ford, transportation expenses are included in production and operating expenses.

Risk Management

We employ a comprehensive risk management program to reduce the volatility in our FFO. For Q1/2015, we have entered into hedges on approximately 51% of our net WTI exposure with 43% fixed at US$93.19/bbl and 7% receiving WTI plus US$11.50/bbl when WTI is below US$80.00/bbl. The unrealized financial derivatives gain with respect to our WTI hedges as at December 31, 2014 was $175 million. The following table summarizes our WTI hedges in place for 2015 as at March 4, 2015.

	Q1/2015	**Q2/2015**	**Q3/2015**	**Q4/2015**	**2015**
Fixed Hedges					
Volumes (bbl/d)	20,464	12,059	4,000	4,000	10,131
Hedge (%) (1)	43%	26%	9%	9%	22%
Price (US$/bbl)	$93.19	$90.56	$95.98	$95.98	$92.96
Floating Hedges					
Volumes (bbl/d)	3,697	3,261	3,312	—	2,567
Hedge (%) (1)	7%	7%	7%	—	5%
Price (US$/bbl) (2)	WTI + $11.50	WTI + $10.65	WTI + $10.00	—	WTI + $10.75
Total Hedge Volume					
Volumes (bbl/d)	24,161	15,320	7,312	4,000	12,698
Hedge (%) (1)	51%	33%	16%	9%	27%

(1) Percentage of hedged volumes based on the mid-point of our 2015 production guidance (excluding NGLs), net of royalties.
(2) Hedges reflect our exposure when WTI is less than US$80/bbl.

As part of our hedging program, we also focus on opportunities to mitigate the volatility in WCS price differentials by transporting crude oil to markets by rail when economics warrant. Baytex has no fixed investment or take or pay obligations to transport crude oil by rail and infrastructure growth around our core heavy oil producing regions allows for optimization between rail and pipe on a month by month basis. In Q4/2014, approximately 24,000 bbl/d of our heavy oil volumes were delivered to market by rail, down slightly from the previous quarter. For Q1/2015, we expect to deliver approximately 20,000 to 22,000 bbl/d of our heavy oil volumes to market by rail as we optimize our heavy oil netbacks.

Financial Liquidity

Total monetary debt at December 31, 2014 was $2.3 billion, comprised of a bank loan of $0.7 billion, long-term debt of $1.4 billion, and a working capital deficiency of $0.2 billion. We have unsecured revolving credit facilities consisting of a $1.0 billion Canadian facility and a US$200 million U.S. facility that mature in June 2018. At the end of December, we had approximately $565 million in undrawn capacity on these facilities. The revolving credit facilities do not require any mandatory principal payments prior to maturity and can be further extended beyond June 2018 with the consent of the lenders.

The unsecured revolving credit facilities in place at December 31, 2014 had the following financial covenants: Senior Debt to Bank EBITDA (twelve month trailing) at or below 3.0:1; Senior Debt to capitalization at or below 0.5:1; and Total Debt to Bank EBITDA (twelve month trailing) at or below 4.0:1. On February 20, 2015, we reached an agreement with our lending syndicate to amend the financial covenants as follows: (a) the maximum Senior Debt to capitalization ratio will be 0.65:1.00 for the period December 31, 2014 up to and including December 31, 2016, and 0.55:1.00 thereafter; (b) the maximum Senior Debt to Bank EBITDA ratio will be 4.75:1.00 for the period December 31, 2014 up to and including June 30, 2016, 4.50:1.00 for the period July 1, 2016 up to and including December 31, 2016 and 3.50:1.00 thereafter; and (c) the maximum Total Debt to Bank EBITDA will be 4.75:1.00 for the period December 31, 2014 up to and including December 31, 2016, and 4.00:1.00 thereafter.

The following table lists the financial covenants under the revolving credit facilities and the senior unsecured notes, and the compliance therewith as at December 31, 2014.

Covenant Description	**Covenant as at February 20, 2015**	**Covenant as at December 31, 2014**	**Position as at December 31, 2014**
Revolving Credit Facilities	**Maximum Ratio**	**Maximum Ratio**	
Senior Debt to Capitalization[(1) (2)]	0.65:1.00	0.50:1.00	0.46:1.00
Senior Debt to Bank EBITDA[(1) (5) (6)]	4.75:1.00	3.00:1.00	1.72:1.00
Total Debt to Bank EBITDA[(3) (5) (6)]	4.75:1.00	4.00:1.00	1.72:1.00
Senior Unsecured Notes	**Minimum Ratio**	**Minimum Ratio**	
Fixed Charge Coverage[(4)]	2:50:1.00	2.50:1.00	13.51:1.00

(1) "Senior debt" is defined as the sum of our bank loan and principal amount of long-term debt.

(2) "Capitalization" is defined as the sum of our bank loan, principal amount of long-term debt and shareholders' equity.

(3) "Total debt" is defined as the sum of our bank loan, the principal amount of long-term debt, and certain other liabilities identified in the credit agreement.

(4) Fixed charge coverage is computed as the ratio of financing costs to trailing twelve month adjusted income, as defined in the note indentures. Adjusted income for the trailing twelve months ended December 31, 2014 was $1.22 billion, including earnings of Aurora on a pro forma basis.

(5) For purposes of the covenant calculations, Aurora's Bank EBITDA for the trailing twelve months has been included, in accordance with the terms of the credit agreement.

(6) Bank EBITDA is calculated based on terms and definitions set out in the credit agreement which adjusts net income for financing costs, income tax, certain specific unrealized and non-cash transactions (including depletion, depreciation, amortization, exploration expenses, unrealized gains and losses on financial derivatives and foreign exchange, and stock based compensation) and acquisition and disposition activity (excluding acquisition-related costs incurred) and is calculated based on a trailing twelve month basis.

Current Outlook

We are committed to our growth and income business model and its three fundamental principles: delivering organic production growth, paying a meaningful dividend and maintaining capital discipline. When oil prices fall as precipitously as they have, this can put stress on any business model. However, we believe we are taking the right steps to weather the current downturn and we will continue to prudently manage our business in order to preserve financial flexibility. Adjusting our dividend level in December was a decision not taken lightly by our Board of Directors, but one that was necessary in order to enhance our liquidity. At the same time, we have reduced our exploration and development spending for 2015 by approximately 40% from what we had originally planned. Operationally, we have some of the strongest capital efficiencies across our portfolio which allows us to add production at relatively low capital costs per barrel. We have also amended the financial covenants contained in our revolving credit facilities which provide us with increased financial flexibility. We remain focused on creating long-term value for our shareholders.

Year-end 2014 Reserves

Baytex's year-end 2014 proved and probable reserves were evaluated by Sproule Unconventional Limited (“Sproule”) and Ryder Scott Company, L.P. (“Ryder Scott”), both independent qualified reserves evaluators. Sproule prepared our reserves report by consolidating the Canadian properties evaluated by Sproule with the United States properties evaluated by Ryder Scott, in each case using Sproule's January 1, 2015 forecast price and cost assumptions. We also had Ryder Scott audit the possible reserves associated with our Eagle Ford assets. All of Baytex's oil and gas properties were evaluated or audited in accordance with National Instrument 51-101 “Standards of Disclosure for Oil and Gas Activities” (“NI 51-101”). Reserves associated with our thermal heavy oil projects at Peace River, Gemini (Cold Lake) and Kerrobert have been classified as bitumen. Finding and development (“F&D”) and finding, development and acquisition (“FD&A”) costs are all reported inclusive of future development costs (“FDC”). Complete reserves disclosure will be included in our Annual Information Form for the year ended December 31, 2014, which will be filed in March 2015.

Our 2014 reserves report reflects significant growth associated with our Eagle Ford acquisition and the subsequent strong drilling results and reduced well spacing. In the Eagle Ford, our proved reserves increased 57% from the time of the acquisition to 167.3 mmboe, and proved plus probable reserves increased 13% from the time of the acquisition to 188.0 mmboe. We have also recognized 220.5 mmboe of possible reserves, which reflects the significant upside for the Austin Chalk and Upper Eagle Ford formations. Our FD&A cost (including future development costs) for the Eagle Ford, including the purchase price and subsequent 2014 development is $25.37/boe.

In aggregate, our proved reserves increased 78% to 283 mmboe (a 33% increase on a per share basis) and proved plus probable reserves increased 36% to 432 mmboe (a 2% increase on a per share basis). Year-end 2014 proved plus probable reserves are comprised of 84% oil and NGLs and 16% natural gas. Proved developed producing (“PDP”) reserves represent 28% of our proved plus probable reserves (up from 22% at year-end 2013) and proved reserves represent 66% of proved plus probable reserves (up from 50% at year-end 2013).

The addition of the Eagle Ford assets to our portfolio provides us with exposure to one of the premier oil resource plays in North America. The high quality Eagle Ford reserves base generates the strongest capital efficiencies in our development inventory, provides the highest cash netbacks and has a significant and growing inventory of development prospects.

Our suite of heavy oil assets at Peace River and Lloydminster also provide strong capital efficiencies. At Peace River, our proved plus probable reserves (excluding thermal) increased 8% to 72.6 mmboe as a result of 10.4 mmboe of drilling extensions and positive technical revisions and 4.1 mmboe related to an asset acquisition. At Lloydminster, we divested 4.3 mmboe of reserves and recorded a 5.2 mmboe negative technical revision at our Tangleflags property. This revision was primarily due to the removal of undeveloped locations and future recompletions which are no longer in our development plan. The revision at Tangleflags was offset by approximately 5.9 mmboe of additions and extensions in the Lloydminster area.

With the addition of the Eagle Ford assets the timeline with respect to the development of our thermal projects is changing. At Cliffdale, Pad 5 no longer falls within our five-year business plan and, as a result, we recorded an 8.8 mmbbl negative technical revision and transferred these reserves into contingent resources. At Gemini, our proved plus probable bitumen reserves were largely unchanged at 43.4 mmbbl, although the project scope has changed resulting in reserves additions that offset technical revisions.

In aggregate, we replaced 118% of production through exploration and development activities (excluding acquisitions and divestitures) with F&D costs of $19.77/boe. Three-year average (2012-2014) F&D costs are $19.55/boe. Inclusive of acquisitions and divestitures, we replaced 497% of production with FD&A costs of $31.10/boe. Three-year average (2012-2014) FD&A costs are $23.99/boe.

Excluding 2014 divestitures, our FD&A costs for 2014 are $27.56/boe, an improvement of 13% over our reported FD&A, which reflects the weaker capital efficiencies of the disposed assets. In 2014, we completed a portfolio review of our asset base, which led to the disposition of several non-core assets. Divestitures totaled $466 million in 2014 and included 63.5 mmboe of proved plus probable reserves. Inclusive of future development costs, the divestitures occurred at a price of $19.63/boe.

We highlight in the table below the efficiency of our capital development program. Excluding our thermal projects, our F&D costs for 2014 were $11.71/boe on a proved plus probable basis which generated a strong recycle ratio of 3.1x. A more detailed three-year summary of our corporate capital efficiencies can be found on page 16.

Efficiency of Capital Development Program (excluding Acquisitions and Divestitures)

	As Reported	Excluding Thermal
Exploration and Development Expenditures ($ millions)	$ 766.1	$ 727.2
Change in Proved plus Probable FDC ($ millions)	(102.0)	(222.6)
Total	$ 664.1	$ 504.6
Proved plus Probable Reserves Additions (mmboe) (1)	33,598	43,114
F&D costs ($/boe)	$ 19.77	$ 11.71
Production Replacement (2)	118%	151%
Recycle Ratio (3)	1.8x	3.1x

(1) Reserves additions include technical revisions.

(2) Production Replacement ratio is calculated as total reserves additions divided by annual production.

(3) Recycle ratio is calculated as operating netback divided by F&D costs (proved plus probable including FDC). Operating netback is calculated as revenue (excluding realized hedging gains and losses) minus royalties, production and operating expenses and transportation expenses.

Eagle Ford Reserves

On June 11, 2014, we acquired an interest in 22,200 net acres in the Sugarkane area located in South Texas in the core of the liquids-rich Eagle Ford shale for approximately $2.8 billion. Since the time of acquisition, we have acquired additional acreage in Sugarkane, bringing the total land position to 22,900 net acres. At the time of the acquisition, we had estimated 106.5 mmboe of proved reserves and 166.5 mmboe of proved plus probable reserves. Reflective of our strong drilling results in 2014 and reduced well spacing in the Lower Eagle Ford formation, our proved reserves have increased 57% to 167.3 mmboe, and our proved plus probable reserves have increased 13% to 188.0 mmboe. Our proved reserves represent 89% of our proved plus probable reserves, up from 64% at the time of the acquisition. The following table reconciles the changes in our Eagle Ford reserves during 2014.

(mmboe)	Proved	Proved + Probable	Possible (1)
June 11, 2014	106.5	166.5	—
Additions, net of revisions	68.0	28.7	220.5
Production	(7.2)	(7.2)	—
December 31, 2014	167.3	188.0	220.5

(1) Possible reserves are those reserves that are less certain to be recovered than probable reserves. There is a 10% probability that the quantities actually recovered will equal or exceed the sum of proved plus probable plus possible reserves.

Ryder Scott assigned a total of 196 net proved undeveloped and probable well locations to the year-end reserves report. Approximately 96% of the well locations are targeting the Lower Eagle Ford formation with the remainder attributable to the Austin Chalk. We have not assigned any proved plus probable undeveloped reserves to the Upper Eagle Ford formation.

In addition to our proved plus probable reserves, we have recognized 220.5 mmboe of possible reserves, representing 389 net well locations. The possible reserves reflect the significant upside potential of the Austin Chalk and Upper Eagle Ford formations. Possible reserves are those reserves that are less certain to be recovered than probable reserves.

Our FD&A cost (including future development costs) for the Eagle Ford, including the purchase price and subsequent 2014 development is $25.37/boe. In 2014, we generated a netback in the Eagle Ford of $39.25/boe which resulted in a strong recycle ratio of 1.5x.

Heavy Oil Reserves

Reserves associated with our heavy oil assets are located at Peace River and Lloydminster. Proved plus probable reserves at year-end 2014 totalled 122.1 mmboe, down 4% from 126.6 mmboe at year-end 2013. The following table reconciles the changes in our proved plus probable reserves (mmboe) for these areas during 2014.

(mmboe)	Peace River	Lloydminster	Total
December 31, 2013	67.4	59.2	126.6
Additions, net of revisions	14.5	(3.6)	11.0
Production	(9.4)	(6.1)	(15.5)
December 31, 2014	72.6	49.5	122.1

Note: Includes approximately 3 mmboe of natural gas reserves associated with heavy oil production.

At Peace River, our proved plus probable reserves increased 8% to 72.6 mmboe as a result of 10.4 mmboe of drilling extensions and positive technical revisions and 4.1 mmboe related to an asset acquisition. At Lloydminster, we divested of 4.3 mmboe of reserves and recorded a 5.2 mmboe negative technical revision at our Tangleflags property. This revision was primarily due to the removal of undeveloped locations and future recompletions which are no longer in our development plan. The revision at Tangleflags was offset by approximately 5.9 mmboe of additions and extensions in the Lloydminster area.

Thermal Reserves

Reserves associated with our thermal heavy oil projects at Peace River, Gemini (Cold Lake) and Kerrobert have been classified as bitumen, in accordance with NI 51-101. Proved plus probable bitumen reserves at year-end total 91.1 mmbbls, down 11% from 101.9 mmbbls at year-end 2013, and now represent 21% of our proved plus probable reserves, compared to 32% one-year ago. The following table reconciles the changes in our proved plus probable bitumen reserves during 2014.

(mmboe)	Cliffdale	Gemini	Kerrobert	Total
December 31, 2013	46.7	43.6	11.6	101.9
Additions, net of revisions	(8.8)	(0.1)	(0.7)	(9.6)
Production	(0.2)	(0.1)	(0.9)	(1.2)
December 31, 2014	37.7	43.4	10.0	91.1

At Cliffdale, our proved plus probable bitumen reserves total 37.7 mmbbls, down 19% from December 31, 2013. We continued to progress our thermal cyclic steam stimulation (“CSS”) operations in 2014. Pad 1 consists of ten wells that were completed in 2012 and Pad 2 consists of 15 wells completed in 2014. We have submitted regulatory applications for the proposed expansion of Pads 3 and 4, each of which would consist of 15 wells. There were no technical revisions associated with Pads 1 through 4. Pad 5 no longer falls within our five-year business plan and, as a result, we recorded an 8.8 mmbbl negative technical revision and transferred these reserves into contingent resources.

At Gemini, our proved plus probable bitumen reserves were largely unchanged at 43.4 mmbbls. In 2014, we drilled 15 stratigraphic wells in the development area to fully delineate the bitumen resource. In December 2014, with the information from the stratigraphic wells and revised facility engineering, Baytex submitted a scheme amendment application to the Alberta Energy Regulator to modify the facility size to 5,000 bbl/d and add two additional resource areas to the existing development approval. We recorded a negative technical revision of 26.4 mmbbls associated with the original development area as we redefined the scope of the project, which was offset by the addition of 26.4 mmbbls associated with the two additional resource areas.

2014 Asset Sales Impact on Reserves

In 2014, we completed a portfolio review of our asset base which led to the disposition of several non-core assets. In aggregate, divestitures totaled $466 million and included 63.5 mmboe of proved plus probable reserves. Inclusive of future development costs, the divestitures occurred at a price of $19.63/boe.

The largest divestiture was our North Dakota assets which we sold for gross proceeds of approximately $357 million and included 53.5 million boe (81% oil and NGL) of proved plus probable reserves as of December 31, 2013.

Excluding 2014 divestitures, our FD&A costs for 2014 are $27.56/boe, an improvement of 13% over our reported FD&A costs of $31.10/boe, which reflects the weaker capital efficiencies of the disposed assets.

Petroleum and Natural Gas Reserves as at December 31, 2014

The following table sets forth our gross and net reserves volumes at December 31, 2014 by product type and reserves category using Sproule's forecast prices and costs. Please note that the data in the table may not add due to rounding.

CANADA	Forecast Prices and Costs					
	Heavy Oil		Bitumen		Light and Medium Oil	
Reserves Category	Gross[1] (mbbl)	Net[2] (mbbl)	Gross[1] (mbbl)	Net[2] (mbbl)	Gross[1] (mbbl)	Net[2] (mbbl)
Proved						
Developed Producing	42,428	31,736	9,763	8,128	3,423	2,955
Developed Non-Producing	6,350	5,365	—	—	6	6
Undeveloped	29,367	23,576	8,295	6,764	307	270
Total Proved	78,145	60,677	18,058	14,892	3,736	3,231
Probable	39,777	30,763	73,054	56,008	2,496	2,080
Total Proved Plus Probable	117,922	91,440	91,112	70,900	6,232	5,311

CANADA	Forecast Prices and Costs					
	Natural Gas Liquids		Natural Gas		Oil Equivalent[3]	
Reserves Category	Gross[1] (mbbl)	Net[2] (mbbl)	Gross[1] (mmcf)	Net[2] (mmcf)	Gross[1] (mboe)	Net[2] (mboe)
Proved						
Developed Producing	1,489	1,072	52,407	43,334	65,838	51,113
Developed Non-Producing	124	85	2,686	2,186	6,928	5,820
Undeveloped	1,075	882	24,699	21,090	43,160	35,006
Total Proved	2,688	2,038	79,793	66,611	115,925	91,939
Probable	2,514	1,948	59,067	50,007	127,685	99,135
Total Proved Plus Probable	5,201	3,987	138,860	116,617	243,610	191,074

UNITED STATES	Forecast Prices and Costs					
	Shale Oil		Natural Gas Liquids		Shale Gas	
Reserves Category	Gross[1] (mbbl)	Net[2] (mbbl)	Gross[1] (mbbl)	Net[2] (mbbl)	Gross[1] (mmcf)	Net[2] (mmcf)
Proved						
Developed Producing	21,256	15,668	22,167	16,358	46,252	34,144
Developed Non-Producing	—	—	—	—	—	—
Undeveloped	28,077	20,690	56,728	41,769	139,352	102,666
Total Proved	49,333	36,358	78,895	58,126	185,604	136,810
Probable	4,546	3,352	10,240	7,551	22,543	16,618
Total Proved Plus Probable	53,879	39,710	89,135	65,677	208,147	153,428
Possible[4][5]	31,931	23,507	131,828	96,617	299,212	219,604
Total Proved Plus Probable Plus Possible	85,810	63,217	220,963	162,294	507,359	373,031

UNITED STATES	Forecast Prices and Costs			
	Natural Gas		Oil Equivalent(3)	
Reserves Category	Gross(1) (mmcf)	Net(2) (mmcf)	Gross(2) (mboe)	Net(2) (mbbl)
Proved				
Developed Producing	22,261	16,400	54,842	40,450
Developed Non-Producing	—	—	—	—
Undeveloped	26,708	19,690	112,481	82,851
Total Proved	48,969	36,090	167,323	123,301
Probable	12,824	9,467	20,680	15,250
Total Proved Plus Probable	61,793	45,557	188,003	138,551
Possible(4)(5)	40,964	30,182	220,455	161,755
Total Proved Plus Probable Plus Possible	102,757	75,739	408,458	300,306

TOTAL	Forecast Prices and Costs					
	Heavy Oil		Bitumen		Light and Medium Oil	
Reserves Category	Gross(1) (mbbl)	Net(2) (mbbl)	Gross(1) (mbbl)	Net(2) (mbbl)	Gross(1) (mbbl)	Net(2) (mbbl)
Proved						
Developed Producing	42,428	31,736	9,763	8,128	3,423	2,955
Developed Non-Producing	6,350	5,365	—	—	6	6
Undeveloped	29,367	23,576	8,295	6,764	307	270
Total Proved	78,145	60,677	18,058	14,892	3,736	3,231
Probable	39,777	30,763	73,054	56,008	2,496	2,080
Total Proved Plus Probable	117,922	91,440	91,112	70,900	6,232	5,311
Possible(4)(5)	—	—	—	—	—	—
Total Proved Plus Probable Plus Possible	117,922	91,440	91,112	70,900	6,232	5,311

TOTAL	Forecast Prices and Costs					
	Shale Oil		Natural Gas Liquids		Shale Gas	
Reserves Category	Gross(1) (mbbl)	Net(2) (mbbl)	Gross(1) (mbbl)	Net(2) (mbbl)	Gross(1) (mmcf)	Net(2) (mmcf)
Proved						
Developed Producing	21,256	15,668	23,656	17,429	46,252	34,144
Developed Non-Producing	—	—	124	85	—	—
Undeveloped	28,077	20,690	57,802	42,650	139,352	102,666
Total Proved	49,333	36,358	81,583	60,165	185,604	136,810
Probable	4,546	3,352	12,753	9,499	22,543	16,618
Total Proved Plus Probable	53,879	39,710	94,336	69,664	208,147	153,428
Possible(4)(5)	31,931	23,507	131,828	96,617	299,212	219,604
Total Proved Plus Probable Plus Possible	85,810	63,217	226,164	166,281	507,359	373,031

TOTAL

	Forecast Prices and Costs			
	Natural Gas		Oil Equivalent[3]	
Reserves Category	Gross[1] (mmcf)	Net[2] (mmcf)	Gross[1] (mboe)	Net[2] (mboe)
Proved				
Developed Producing	74,668	59,734	120,680	91,563
Developed Non-Producing	2,686	2,186	6,928	5,820
Undeveloped	51,407	40,780	155,641	117,857
Total Proved	128,762	102,701	283,249	215,240
Probable	71,891	59,474	148,365	114,385
Total Proved Plus Probable	200,653	162,174	431,614	329,624
Possible[4][5]	40,964	30,182	220,455	161,755
Total Proved Plus Probable Plus Possible	241,617	192,356	652,069	491,379

Notes:

(1) “Gross” reserves means the total working and royalty interest share of remaining recoverable reserves owned by Baytex before deductions of royalties payable to others.

(2) “Net” reserves means Baytex's gross reserves less all royalties payable to others.

(3) Oil equivalent amounts have been calculated using a conversion rate of six thousand cubic feet of natural gas to one barrel of oil. BOEs may be misleading, particularly if used in isolation. A boe conversion ratio of six thousand cubic feet of natural gas to one barrel of oil is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

(4) Possible reserves are those reserves that are less certain to be recovered than probable reserves. There is a 10% probability that the quantities actually recovered will equal or exceed the sum of proved plus probable plus possible reserves.

(5) The total possible reserves include only possible reserves from the Eagle Ford assets. The possible reserves associated with the Canadian properties have not been evaluated.

Reserves Reconciliation

The following table reconciles the year-over-year changes in our gross reserves volumes by product type and reserves category using Sproule's forecast prices and costs. Please note that the data in table may not add due to rounding.

Reconciliation of Gross Reserves (2)
By Principal Product Type
Forecast Prices and Costs

	Heavy Oil			Bitumen		
Gross Reserves Category	**Proved (mbbl)**	**Probable (mbbl)**	**Proved + Probable (mbbl)**	**Proved (mbbl)**	**Probable (mbbl)**	**Proved + Probable (mbbl)**
December 31, 2013	82,903	42,643	125,547	19,322	82,564	101,886
Extensions	5,447	3,946	9,393	—	—	—
Infill Drilling	2,661	1,081	3,742	—	—	—
Improved Recoveries	41	8	49	—	26,393	26,393
Technical Revisions	1,226	(7,120)	(5,893)	2	(35,919)	(35,917)
Discoveries	—	—	—	—	—	—
Acquisitions	4,064	1,325	5,389	—	—	—
Dispositions	(3,011)	(2,090)	(5,101)	—	—	—
Economic Factors	(11)	(18)	(28)	(8)	16	8
Production	(15,175)	—	(15,175)	(1,258)	—	(1,258)
December 31, 2014	78,145	39,777	117,922	18,058	73,054	91,112

	Light and Medium Crude Oil			Shale Oil		
Gross Reserves Category	**Proved (mbbl)**	**Probable (mbbl)**	**Proved + Probable (mbbl)**	**Proved (mbbl)**	**Probable (mbbl)**	**Proved + Probable (mbbl)**
December 31, 2013	35,949	16,765	52,714	—	—	—
Extensions	—	—	—	—	—	—
Infill Drilling	102	21	123	14,044	(8,822)	5,222
Improved Recoveries	—	—	—	—	—	—
Technical Revisions	(583)	(277)	(860)	—	—	—
Discoveries	—	—	—	—	—	—
Acquisitions	—	—	—	38,506	13,367	51,873
Dispositions	(29,912)	(14,018)	(43,930)	—	—	—
Economic Factors	(39)	4	(35)	—	—	—
Production	(1,780)	—	(1,780)	(3,217)	—	(3,217)
December 31, 2014	3,736	2,496	6,232	49,333	4,546	53,879

	Natural Gas Liquids			Shale Gas		
Gross Reserves Category	**Proved (mbbl)**	**Probable (mbbl)**	**Proved + Probable (mbbl)**	**Proved (mmcf)**	**Probable (mmcf)**	**Proved + Probable (mmcf)**
December 31, 2013	3,073	3,469	6,542	—	—	—
Extensions	81	808	889	—	—	—
Infill Drilling	37,458	(20,441)	17,017	99,144	(60,022)	39,122
Improved Recoveries	—	—	—	—	—	—
Technical Revisions	826	(821)	5	—	—	—
Discoveries	—	—	—	—	—	—
Acquisitions	44,133	30,693	74,826	93,969	82,564	176,533
Dispositions	(749)	(950)	(1,699)	—	—	—
Economic Factors	(24)	(5)	(28)	—	—	—
Production	(3,216)	—	(3,216)	(7,508)	—	(7,508)
December 31, 2014	81,583	12,753	94,336	185,604	22,543	208,147

Gross Reserves Category	Natural Gas Proved (mmcf)	Natural Gas Probable (mmcf)	Natural Gas Proved + Probable (mmcf)	Oil Equivalent(3) Proved (mboe)	Oil Equivalent(3) Probable (mboe)	Oil Equivalent(3) Proved + Probable (mboe)
December 31, 2013	109,665	78,896	188,561	159,524	158,592	318,115
Extensions	1,666	16,148	17,813	5,806	7,445	13,251
Infill Drilling	1,395	436	1,831	71,021	(38,092)	32,929
Improved Recoveries	2	—	2	42	26,401	26,443
Technical Revisions	37,730	(11,939)	25,791	7,759	(46,126)	(38,366)
Discoveries	—	—	—	—	—	—
Acquisitions	49,312	12,824	62,136	110,583	61,284	171,866
Dispositions	(49,182)	(27,197)	(76,379)	(41,869)	(21,591)	(63,459)
Economic Factors	(5,523)	2,723	(2,800)	(1,003)	452	(551)
Production	(16,302)	—	(16,302)	(28,614)	—	(28,614)
December 31, 2014	128,762	71,891	200,653	283,249	148,365	431,614

Notes:

(1) "Gross" reserves means the total working and royalty interest share of remaining recoverable reserves owned by Baytex before deductions of royalties payable to others.

(2) Reserve information as at December 31, 2014 and 2013 is prepared in accordance with NI 51-101.

(3) Oil equivalent amounts have been calculated using a conversion rate of six thousand cubic feet of natural gas to one barrel of oil. BOEs may be misleading, particularly if used in isolation. A boe conversion ratio of 6 mcf:1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

Reserves Life Index

The following table sets forth our reserves life index based on proved and proved plus probable reserves at year-end 2014 and the mid-point of our 2015 production guidance of 86,000 boe/d.

	Mid-Point of 2015 Production Guidance	Reserves Life Index (years) Proved	Reserves Life Index (years) Proved Plus Probable
Oil and NGL (bbl/d)	70,520	9.0	14.1
Natural Gas (mcf/d)	92,880	9.3	12.1
Oil Equivalent (boe/d)	86,000	9.0	13.8

Capital Program Efficiency

Based on the evaluation of our petroleum and natural gas reserves prepared in accordance with NI 51-101 by our independent qualified reserves evaluators, the efficiency of our capital programs (including FDC) is summarized in the following table.

	2014	2013	2012	Three-Year Total / Average 2012 - 2014
Capital Expenditures ($ millions)				
Exploration and development	$ 766.1	$ 550.9	$ 418.6	$ 1,735.6
Acquisitions (net of dispositions)	2,545.1	(39.1)	(170.9)	2,335.1
Total	$ 3,311.2	$ 511.8	$ 247.7	$ 4,070.7
Change in Future Development Costs – Proved ($ millions)				
Exploration and development	$ (248.5)	$ 300.8	$ 117.8	$ 170.1
Acquisitions (net of dispositions)	1,312.9	(39.3)	(167.9)	1,105.7
Total	$ 1,064.4	$ 261.5	$ (50.1)	$ 1,275.8
Change in Future Development Costs – Proved plus Probable ($ millions)				
Exploration and Development	$ (102.0)	$ 393.7	$ 244.2	$ 535.9
Acquisitions (net of dispositions)	1,210.5	(39.3)	189.3	1,360.5
Total	$ 1,108.5	$ 354.4	$ 435.5	$ 1,896.4
Proved Reserves Additions (mboe)				
Exploration and development	83,515	38,117	18,411	140,044
Acquisitions (net of dispositions)	68,824	(1,160)	(11,769)	55,895
Total	152,339	36,957	6,642	195,938
Proved plus Probable Reserves Additions (mboe)				
Exploration and development	33,598	48,936	33,659	116,193
Acquisitions (net of dispositions)	108,515	(1,540)	25,523	132,498
Total	142,113	47,396	59,182	248,691
F&D costs ($/boe)				
Proved	$ 6.20	$ 22.34	$ 29.14	$ 13.61
Proved plus probable	$ 19.77	$ 19.30	$ 19.69	$ 19.55
FD&A costs ($/boe)				
Proved	$ 28.72	$ 20.92	$ 29.75	$ 27.29
Proved plus probable	$ 31.10	$ 18.28	$ 11.51	$ 23.99
Ratios (based on proved plus probable reserves)				
Production replacement [(1)]	497%	227%	300%	359%
Recycle ratio [(2)]	1.8x	1.7x	1.6x	1.7x

Notes:

(1) Production Replacement ratio is calculated as total reserves additions (including acquisitions and divestitures) divided by annual production.

(2) Recycle ratio is calculated as operating netback divided by F&D costs (proved plus probable including FDC). Operating netback is calculated as revenue (excluding realized hedging gains and losses) minus royalties, production and operating expenses and transportation expenses.

Net Present Value of Reserves (Forecast Prices and Costs)

The following table summarizes Sproule and Ryder Scott's estimate of the net present value before income taxes of the future net revenue attributable to our reserves using Sproule's forecast prices and costs (and excluding the impact of any hedging activities). Please note that the data in the table may not add due to rounding.

Summary of Net Present Value of Future Net Revenue
As at December 31, 2014
Forecast Prices and Costs
Before Income Taxes and Discounted at (%/year)

CANADA

Reserves Category	0% ($000s)	5% ($000s)	10% ($000s)	15% ($000s)	20% ($000s)
Proved					
Developed Producing	$ 1,767,983	$ 1,467,827	$ 1,259,500	$ 1,107,199	$ 991,311
Developed Non-Producing	238,357	169,627	127,382	99,693	80,550
Undeveloped	1,122,000	812,642	605,669	461,548	357,787
Total Proved	3,128,340	2,450,097	1,992,552	1,668,440	1,429,648
Probable	3,877,356	2,104,276	1,282,788	845,561	586,769
Total Proved Plus Probable	$ 7,005,696	$ 4,554,373	$ 3,275,340	$ 2,514,000	$ 2,016,417

UNITED STATES

Reserves Category	0% ($000s)	5% ($000s)	10% ($000s)	15% ($000s)	20% ($000s)
Proved					
Developed Producing	$ 1,707,246	$ 1,330,374	$ 1,093,873	$ 934,314	$ 820,303
Developed Non-Producing					
Undeveloped	2,395,266	1,505,012	982,948	654,064	435,208
Total Proved	4,102,511	2,835,386	2,076,821	1,588,379	1,255,510
Probable	708,159	438,018	306,608	232,914	186,785
Total Proved Plus Probable	4,810,670	3,273,404	2,383,429	1,821,293	1,442,295
Possible (1)	5,396,827	2,388,440	1,154,269	593,860	318,479
Total Proved Plus Probable Plus Possible (1)	$ 10,207,497	$ 5,661,844	$ 3,537,698	$ 2,415,153	$ 1,760,774

TOTAL

Reserves Category	0% ($000s)	5% ($000s)	10% ($000s)	15% ($000s)	20% ($000s)
Proved					
Developed Producing	$ 3,475,229	$ 2,798,201	$ 2,353,373	$ 2,041,513	$ 1,811,614
Developed Non-Producing	238,357	169,627	127,382	99,693	80,550
Undeveloped	3,517,266	2,317,654	1,588,617	1,115,612	792,995
Total Proved	7,230,851	5,285,483	4,069,373	3,256,819	2,685,158
Probable	4,585,514	2,542,295	1,589,396	1,078,476	773,554
Total Proved Plus Probable	11,816,366	7,827,777	5,658,769	4,335,293	3,458,712
Possible (1)(2)	5,396,827	2,388,440	1,154,269	593,860	318,479
Total Proved Plus Probable Plus Possible (1)(2)	$ 17,213,193	$ 10,216,217	$ 6,813,038	$ 4,929,153	$ 3,777,191

(1) Possible reserves are those reserves that are less certain to be recovered than probable reserves. There is a 10% probability that the quantities actually recovered will equal or exceed the sum of proved plus probable plus possible reserves.
(2) The total possible reserves include only possible reserves from the Eagle Ford assets. The possible reserves associated with the Canadian properties have not been evaluated.

The net present values noted in the table above do not include any value for future net revenue which may ultimately be generated from the contingent resources discussed later in this press release.

Sproule December 31, 2014 Forecast Prices

The following table summarizes the forecast prices used by Sproule in preparing the estimated reserves volumes and the net present values of future net revenues at December 31, 2014.

Year	WTI Cushing US$/bbl	Edmonton Par C$/bbl	Western Canada Select C$/bbl	AECO-C Spot C$/MMbtu	Inflation Rate %/Yr	Exchange Rate $US/$Cdn
2014 act.	93.00	94.18	82.04	4.50	1.4	0.905
2015	65.00	70.35	60.50	3.32	1.5	0.850
2016	80.00	87.36	75.13	3.71	1.5	0.870
2017	90.00	98.28	84.52	3.90	1.5	0.870
2018	91.35	99.75	85.79	4.47	1.5	0.870
2019	92.72	101.25	87.07	5.05	1.5	0.870
Thereafter			Escalation rate of 1.5%			

Future Development Costs

The following table sets forth future development costs deducted in the estimation of the future net revenue attributable to the reserves categories noted below (using forecast prices and costs).

CANADA Year	Proved Reserves ($000s)	Proved Plus Probable Reserves ($000s)
2015	$ 104,669	$ 128,068
2016	206,073	429,652
2017	202,350	442,098
2018	74,063	189,841
2019	26,635	69,754
Remaining	44,672	395,742
Total (Undiscounted)	$ 658,462	$ 1,655,155

UNITED STATES Year	Proved Reserves ($000s)	Proved Plus Probable Reserves ($000s)
2015	$ 313,837	$ 313,837
2016	464,827	464,827
2017	569,130	569,130
2018	280,546	280,546
2019	60,367	60,367
Remaining	31,400	31,400
Total (Undiscounted)	$ 1,720,107	$ 1,720,107

TOTAL Year	Proved Reserves ($000s)	Proved Plus Probable Reserves ($000s)
2015	$ 418,506	$ 441,905
2016	670,900	894,479
2017	771,480	1,011,228
2018	354,609	470,387
2019	87,002	130,121
Remaining	76,071	427,142
Total (Undiscounted)	$ 2,378,568	$ 3,375,261

Undeveloped Land Holdings

The following table sets forth our undeveloped land holdings as at December 31, 2014.

	Undeveloped Acres	
	Gross	**Net**
Canada		
Alberta	588,805	506,150
British Columbia	660	26
Saskatchewan	140,725	133,730
Total Canada	730,190	639,906
United States		
Eagle Ford	2,170	316
East Texas	10,017	9,751
New Mexico	13,812	13,812
Total United States	25,999	23,879
Total Company	756,189	663,785

We estimate the value of our net undeveloped land holdings at December 31, 2014 to be approximately $201 million. This internal evaluation generally represents the estimated replacement cost of our undeveloped land. In determining replacement cost, we analyzed land sale prices paid at Provincial Crown and State land sales for the properties in the vicinity of our undeveloped land holdings, less an allowance for near-term expiries.

Contingent Resources Assessment

We commissioned Sproule to conduct an assessment of contingent resources effective December 31, 2014 on two of our oil resource plays: the Bluesky in the Peace River area of Alberta and the Lower Cretaceous Mannville Group for the Gemini SAGD project. We also commissioned McDaniel & Associates Consultants Ltd. ("McDaniel") to conduct an assessment of contingent resources effective December 31, 2014 on the Lower Cretaceous Mannville Group in northeast Alberta.

Contingent resources represents the quantity of petroleum estimated to be potentially recoverable from known accumulations using established technology or technology under development, but which do not currently qualify as reserves or 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. The outstanding contingencies applicable to our disclosed contingent resources do not include economic contingencies. Economic contingent resources are those resources that are currently economically recoverable based on specific forecasts of commodity prices and costs. The assigned contingent resources are categorized as economically recoverable based on economics completed at year-end 2012.

For the total of these three plays, Sproule and McDaniel's estimate of contingent resources ranges from 577 million barrels of oil equivalent and bitumen in the "low estimate" (C1) to 1,069 million barrels of oil equivalent and bitumen in the "high estimate" (C3), with a "best estimate" (C2) of 747 million barrels of oil equivalent and bitumen. Contingent resources are in addition to currently booked reserves.

The best estimate contingent resources of 747 million barrels of oil equivalent and bitumen represent an approximate 6% reduction in best estimate contingent resources from year-end 2013. Included in this reduction is 34 million barrels of oil equivalent best estimate contingent resources associated with our disposition of assets in the Williston Basin in North Dakota, USA. A further reduction of 8 million barrels of oil equivalent best estimate contingent resources is associated with surrendered lands in the Cold Lake area of Alberta. The remaining changes to our contingent resources assessment include land adjustments, transfer of reserves to resources and the conversion of resources to reserves during the year.

The table below summarizes Sproule and McDaniel's estimates of economic contingent resources for the three plays by geographic area. The contingent resources assessments were prepared in accordance with the definitions, standards and procedures contained in the COGE Handbook and NI 51-101.

	Economic Contingent Resources (gross)(2)(4)(5)		
(millions of barrels of oil equivalent and bitumen)(3)	**Low(6)**	**Best(7)**	**High(8)**
Peace River, Alberta	451	555	802
Northeast Alberta	62	118	183
Gemini SAGD Project – Cold Lake, Alberta	64	74	84
Total	577	747	1,069

Notes:

(1) Contingent resources are defined in the COGE Handbook as "those quantities of petroleum estimated to be potentially recoverable from known accumulations using established technology or technology under development, but which do not currently qualify as reserves or 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."

(2) Economic contingent resources are those resources that are currently economically recoverable based on specific forecasts of commodity prices and costs. The assigned contingent resources are categorized as economically recoverable based on economics completed at year-end 2012.

(3) Under NI 51-101, naturally occurring hydrocarbons with a viscosity greater than 10,000 centipoise are classed as bitumen. The majority of the contingent resources at Peace River and the Gemini SAGD project that will be recovered by thermal processes has a viscosity greater than this value; therefore, this component of the contingent resources is classified as bitumen under NI 51-101.

(4) Sproule and McDaniel prepared the estimates of contingent resources 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. The total volumes presented in the table are arithmetic sums of multiple estimates of contingent resources, 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 contingent resources and appreciate the differing probabilities of recovery associated with each class as explained herein.

(5) Gross means the company's working interest share in the contingent resources before deducting royalties.

(6) Low estimate (C1) is considered to be a conservative estimate of the quantity of resources that will actually be recovered. It is likely that the actual remaining quantities recovered will exceed the low estimate. Those resources in the low estimate have the highest degree of certainty - a 90% confidence level - that the actual quantities recovered will equal or exceed the estimate.

(7) Best estimate (C2) is considered to be the best estimate of the quantity of resources 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 in the best estimate have a 50% confidence level that the actual quantities recovered will equal or exceed the estimate.

(8) High estimate (C3) is considered to be an optimistic estimate of the quantity of resources that will actually be recovered. It is unlikely that the actual remaining quantities of resources recovered will equal or exceed the high estimate. Those resources in the high estimate have a lower degree of certainty - a 10% confidence level - that the actual quantities recovered will equal or exceed the estimate.

There is no certainty that it will be commercially viable to produce any portion of the contingent resources or that we will produce any portion of the volumes currently classified as contingent resources. The recovery and resource estimates provided herein are estimates. Actual contingent resources (and any volumes that may be reclassified as reserves) and future production from such contingent resources may be greater than or less than the estimates provided herein.

Additional Information

Our audited consolidated financial statements for the year ended December 31, 2014 and the related Management's Discussion and Analysis of the operating and financial results can be accessed immediately on our website at www.baytexenergy.com and will be available shortly through SEDAR at www.sedar.com and EDGAR at www.sec.gov/edgar.shtml.

Conference Call Today
9:00 a.m. MST (11:00 a.m. EST)

Baytex will host a conference call today, March 5, 2015, starting at 9:00am MST (11:00am EST). To participate, please dial 416-340-2216 or toll free in North America 1-800-355-4959 and toll free international 1-800-6578-9868. Alternatively, to listen to the conference call online, please enter http://www.gowebcasting.com/6327 in your web browser.

An archived recording of the conference call will be available until March 12, 2015 by dialing toll free 1-800-408-3053 within North America (Toronto local dial 905-694-9451, International toll free 1-800-3366-3052) and entering reservation code 7195646. The conference call will also be archived on the Baytex website at www.baytexenergy.com.

Advisory Regarding 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 in this press release 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"). In some cases, forward-looking statements can be identified by terminology such as "anticipate", "believe", "continue", "could", "estimate", "expect", "forecast", "intend", "may", "objective", "ongoing", "outlook", "potential", "project", "plan", "should", "target", "would", "will" or similar words suggesting future outcomes, events or performance. The forward-looking statements contained in this press release speak only as of the date thereof and are expressly qualified by this cautionary statement.

Specifically, this press release contains forward-looking statements relating to: our business strategies, plans and objectives; our annual average production rate for 2015; our capital budget for 2015; the geographic breakdown of our 2015 annual production; our production mix for 2015; the breakdown of our 2015 capital budget by area; our plan for developing our properties in 2015, including the number and type of wells and the geographic location of wells; our Eagle Ford shale play, including our assessment of the performance of wells drilled in the Eagle Ford in 2014, initial production rates from new wells, the capital efficiency of our Eagle Ford wells relative to other North American projects, our belief that the Eagle Ford has a significant and growing inventory of development prospects to support future growth, and our plans to use "stack and frac" pilots to target three zones in the Eagle Ford formation in addition to the overlying Austin Chalk formation and the timing of receiving the results from such pilots; our Peace River heavy oil resource play, including our plans to implement a water flood pilot and the potential for water floods to enhance ultimate recovery from the field; the timing of completion of the second phase of Genalta Power's Peace River Power Centre and our expectation that it will increase the conservation of our solution gas; our Lloydminster heavy oil properties, including our assessment of a water flood project in the Lloydminster formation; the existence, operation and strategy of our risk management program for commodity prices, heavy oil differentials and interest and foreign exchange rates; our ability to mitigate our exposure to heavy oil price differentials by transporting our crude oil to market by railways; the volume of heavy oil to be transported to market on railways in the first quarter of 2015; our reserves life index; forecast prices for oil and natural gas; forecast inflation and exchange rates; future development costs; and the value of our undeveloped land holdings. 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.

These forward-looking statements are based on certain key assumptions regarding, among other things: our ability to execute and realize on the anticipated benefits of the acquisition of the Eagle Ford assets; petroleum and natural gas prices and pricing differentials between light, medium and heavy gravity crude oil; well production rates and reserves 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 for our operating activities; 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; the continuance of existing and, in certain circumstances, proposed tax and royalty regimes; our ability to develop our crude oil and natural gas properties in the manner currently contemplated; and current industry conditions, laws and regulations continuing in effect (or, where changes are proposed, such changes being adopted as anticipated). 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 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: declines in oil and natural gas prices; risks related to the accessibility, availability, proximity and capacity of gathering, processing and pipeline systems; uncertainties in the credit markets may restrict the availability of credit or increase the cost of borrowing; refinancing risk for existing debt and debt service costs; a downgrade of our credit ratings; risks associated with properties operated by third parties; changes in government regulations that affect the oil and gas industry; changes in environmental, health and safety regulations; variations in interest rates and foreign exchange rates; risks associated with our hedging activities; the cost of developing and operating our assets; risks associated with the exploitation of our properties and our ability to acquire reserves; changes in income tax or other laws or government incentive programs; uncertainties associated with estimating petroleum and natural gas reserves; risks associated with acquiring, developing and exploring for oil and natural gas and other aspects of our operations; risks associated with large projects or expansion of our activities; risks related to heavy oil projects; the implementation of strategies for reducing greenhouse gases; depletion of our reserves; risks associated with the ownership of our securities, including the discretionary nature of dividend payments and changes in market-based factors; risks for United States and other non-resident shareholders, including the ability to enforce civil remedies, differing practices for reporting reserves and production, additional taxation applicable to non-residents and foreign exchange risk; and other factors, many of which are beyond our control. These and additional risk factors are discussed in our Annual Information Form, Annual Report on Form 40-F and Management's Discussion and Analysis for the year ended December 31, 2014, as filed with Canadian securities regulatory authorities and the U.S. Securities and Exchange Commission.

The above summary of assumptions and risks related to forward-looking statements in this press release has been provided in order to provide shareholders and potential investors with a more complete perspective on Baytex's current and future operations and such information may not be appropriate for other purposes. 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.

Non-GAAP Financial Measures

Funds from operations is not a measurement based on Generally Accepted Accounting Principles ("GAAP") in Canada, but is a financial term commonly used in the oil and gas industry. Funds from operations represents cash generated from operating activities adjusted for financing costs, changes in non-cash operating working capital and other operating items. Baytex's determination of funds from operations may not be comparable with the calculation of similar measures for other entities. Baytex considers funds from operations a key measure of performance as it demonstrates its ability to generate the cash flow necessary to fund future dividends to shareholders and capital investments. The most directly comparable measures calculated in accordance with GAAP are cash flow from operating activities and net income.

Total monetary debt is not a measurement based on GAAP in Canada. We define total monetary debt as the sum of monetary working capital (which is current assets less current liabilities (excluding non-cash items such as unrealized gains or losses on financial derivatives, assets held for sale and liabilities related to assets held for sale)), the principal amount of long-term debt and bank loan. We believe that this measure assists in providing a more complete understanding of our cash liabilities.

Bank EBITDA is not a measurement based on GAAP in Canada. We define Bank EBITDA as our consolidated net income attributable to shareholders before interest, taxes, depletion and depreciation, and certain other non-cash items as set out in our credit agreements governing our unsecured revolving credit facilities. This measure is used to measure compliance with certain financial covenants.

Operating netback is not a measurement based on GAAP in Canada, but is a financial term commonly used in the oil and gas industry. Operating netback is equal to product revenue less royalties, production and operating expenses and transportation expenses dividend by barrels of oil equivalent sales volume for the applicable period. Baytex's determination of operating netback may not be comparable with the *calculation of similar measures for other entities. Baytex believes that this measure assists in characterizing our ability to generate cash margin on a unit of production basis.*

Advisory Regarding Oil and Gas Information

The reserves information contained in this press release has been prepared in accordance with National Instrument 51-101 "Standards of Disclosure for Oil and Gas Activities" of the Canadian Securities Administrators ("NI 51-101"). Complete NI 51-101 reserves disclosure will be included in our Annual Information Form for the year ended December 31, 2014, which will be filed in early March 2015. Listed below are cautionary statements that are specifically required by NI 51-101:

- *Where applicable, oil equivalent amounts have been calculated using a conversion rate of six thousand cubic feet of natural gas to one barrel of oil. BOEs may be misleading, particularly if used in isolation. A boe conversion ratio of six thousand cubic feet of natural gas to one barrel of oil is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.*

- *With respect to finding and development costs, the aggregate of the exploration and development costs incurred in the most recent financial year and the change during that year in estimated future development costs generally will not reflect total finding and development costs related to reserves additions for that year.*

- *This press release contains estimates of the net present value of our future net revenue from our reserves. Such amounts do not represent the fair market value of our reserves.*

This press release contains estimates as of December 31, 2014 of the volumes of "contingent resources" for our oil resource plays in the Bluesky in the Peace River area of Alberta, the Mannville group in northeast Alberta and the Gemini steam-assisted gravity drainage project in Cold Lake, Alberta. These estimates were prepared by independent qualified reserves evaluators.

"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." The outstanding contingencies applicable to our disclosed contingent resources do not include economic contingencies. Economic contingent resources are those resources that are currently economically recoverable based on specific forecasts of commodity prices and costs.

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; stakeholder and regulatory approvals; access to required services and field development infrastructure; oil prices; 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 resources or that we will produce any portion of the volumes currently classified as contingent resources. The estimates of contingent resources involve implied assessment, based on certain estimates and assumptions, that the resources described exists in the quantities predicted or estimated and that the resources can be profitably produced in the future.

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

References herein to average 30-day initial production rates and other short-term production rates are useful in confirming the presence of hydrocarbons, however such rates are not determinative of the rates at which such wells will commence production and decline thereafter and are not indicative of long term performance or of ultimate recovery. While encouraging, readers are cautioned not to place reliance on such rates in calculating aggregate production for us or the assets for which such rates are provided. A pressure transient analysis or well-test interpretation has not been carried out in respect of all wells. Accordingly, we caution that the test results should be considered to be preliminary.

Notice to United States Readers

The petroleum and natural gas reserves contained in this press release have generally been prepared in accordance with Canadian disclosure standards, which are not comparable in all respects to United States or other foreign disclosure standards. For example, the United States Securities and Exchange Commission (the "SEC") requires oil and gas issuers, in their filings with the SEC, to disclose only "proved reserves", but permits the optional disclosure of "probable reserves" and "possible reserves" (each as defined in SEC rules). Canadian securities laws require oil and gas issuers disclose their reserves in accordance with NI 51-101, which requires disclosure of not only "proved reserves" but also "probable reserves" and permits the optional disclosure of "possible reserves". Additionally, NI 51-101 defines "proved reserves", "probable reserves" and "possible reserves" differently from the SEC rules. Accordingly, proved, probable and possible reserves disclosed in this press release may not be comparable to United States standards. Probable reserves are higher risk and are generally believed to be less likely to be accurately estimated or recovered than proved reserves. Possible reserves are higher risk than probable reserves and are generally believed to be less likely to be accurately estimated or recovered than probable reserves.

In addition, under Canadian disclosure requirements and industry practice, reserves and production are reported using gross volumes, which are volumes prior to deduction of royalty and similar payments. The SEC rules require reserves and production to be presented using net volumes, after deduction of applicable royalties and similar payments.

Moreover, Baytex has determined and disclosed estimated future net revenue from its reserves using forecast prices and costs, whereas the SEC rules require that reserves be estimated using a 12-month average price, calculated as the arithmetic average of the first-day-of-the-month price for each month within the 12-month period prior to the end of the reporting period. As a consequence of the foregoing, Baytex's reserve estimates and production volumes in this press release may not be comparable to those made by companies utilizing United States reporting and disclosure standards.

We also included in this press release estimates of contingent resources. Contingent resources represent the quantity of petroleum and natural gas estimated to be potentially recoverable from known accumulations using established technology or technology under development, but which do not currently qualify as reserves or 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. The SEC does not permit the inclusion of estimates of resource in reports filed with it by United States companies.

All amounts in this press release are stated in Canadian dollars unless otherwise specified.

Baytex Energy Corp.

Baytex Energy Corp. is a dividend-paying oil and gas corporation based in Calgary, Alberta. The company is engaged in the acquisition, development and production of crude oil and natural gas in the Western Canadian Sedimentary Basin and in the Eagle Ford in the United States. Approximately 82% of Baytex's production is weighted toward crude oil and natural gas liquids. Baytex pays a monthly dividend on its common shares which are traded on the Toronto Stock Exchange and the New York Stock Exchange under the symbol BTE.

For further information about Baytex, please visit our website at www.baytexenergy.com or contact:

Brian Ector, Senior Vice President, Capital Markets and Public Affairs

Toll Free Number: 1-800-524-5521
Email: investor@baytexenergy.com