BAYTEX REPORTS 2015 RESULTS, STRONG RESERVES GROWTH IN THE EAGLE FORD AND REVISED 2016 BUDGET

CALGARY, ALBERTA (March 3, 2016) - Baytex Energy Corp. ("Baytex")(TSX, NYSE: BTE) reports its operating and financial results for the three months and year ended December 31, 2015 (all amounts are in Canadian dollars unless otherwise noted).

"Our 2015 results reflect the strong contribution from our Eagle Ford assets. The Eagle Ford generates the highest cash netbacks in our portfolio and has enhanced the quality of our production and reserves base. In 2015, 86% of our development activity was focused in the Eagle Ford, which contributed to strong reserves growth in our U.S. assets. The execution of our capital program has yielded impressive results as we advance the multi-zone development potential of our Eagle Ford acreage," commented James Bowzer, President and Chief Executive Officer.

Bowzer said, "Based on the current commodity price environment and our commitment to ensuring strong levels of financial liquidity, we are reducing our 2016 exploration and development capital budget to $225 to $265 million, a 33% reduction from initial expectations of $325 to $400 million. In addition, we are proactively shutting-in approximately 7,500 bbl/d of low or negative margin heavy oil production in order to optimize the value of the resource base and maximize our funds from operations. Should netbacks improve, we have the ability to restart these wells in relatively short order at minimal cost. Our 2016 program will remain flexible and allows for adjustments to spending and production based on changes in the commodity price environment."

Highlights

- Generated production of 81,110 boe/d (81% oil and NGL) during Q4/2015 and 84,648 boe/d for the full-year 2015, in line with guidance;

- Delivered funds from operations ("FFO") of $93.1 million ($0.44 per share) in Q4/2015 and $516.4 million ($2.61 per share) for the full-year 2015;

- Produced 40,284 boe/d (78% oil and NGL) in the Eagle Ford during Q4/2015, an increase of 3% over Q3/2015 and 6% over Q4/2014;

- Realized over $150 million in efficiencies in 2015 as we remained focused on cost reduction initiatives across all of our operations, including drilling and completions, production and operating expenses, transportation expenses, and general and administrative expenses;

- Increased proved plus probable reserves (excluding thermal) by 2% to 347 mmboe. Year-end 2015 proved plus probable reserves are comprised of 81% oil and NGL and 19% natural gas;

- In the Eagle Ford, replaced 205% of production and increased proved plus probable reserves 8% to 203 mmboe. From the time of acquisition in June 2014, proved plus probable reserves in the Eagle Ford have increased by 22%;

- Recorded finding and development ("F&D") costs for proved plus probable reserves, including changes in future development costs, of $7.68/boe for 2015 and generated a recycle ratio (operating netback divided by F&D costs) of 2.1x;

- Using the December 31, 2015 independent reserves evaluation, the present value of our reserves, discounted at 10% before tax, is estimated to be $4.3 billion; and

- Our estimated net asset value at year-end 2015, discounted at 10%, is estimated to be $11.05 per share. This is based on the estimated reserves value of $4.3 billion plus a value for undeveloped acreage, net of long-term debt, asset retirement obligations and working capital.

	Three Months Ended			Years Ended	
	December 31, 2015	September 30, 2015	December 31, 2014	**December 31, 2015**	December 31, 2014
FINANCIAL *(thousands of Canadian dollars, except per common share amounts)*					
Petroleum and natural gas sales	**$ 230,200**	$ 268,625	$ 472,390	**$ 1,129,872**	$ 1,969,022
Funds from operations (1)	**93,095**	105,052	245,513	**516,417**	879,790
Per share - basic	**0.44**	0.51	1.47	**2.61**	5.91
Per share - diluted	**0.44**	0.51	1.47	**2.61**	5.91
Cash dividends declared (2)	**—**	17,248	72,509	**96,624**	301,118
Dividends declared per share	**—**	0.20	0.58	**0.80**	2.64
Net income (loss)	**(412,924)**	(517,856)	(361,816)	**(1,133,651)**	(132,807)
Per share - basic	**(1.96)**	(2.49)	(2.16)	**(5.72)**	(0.89)
Per share - diluted	**(1.96)**	(2.49)	(2.16)	**(5.72)**	(0.89)
Exploration and development	**140,796**	126,804	214,697	**521,039**	766,070
Acquisitions, net of divestitures	**(574)**	(498)	(35,666)	**1,648**	2,545,156
Total oil and natural gas capital expenditures	**$ 140,222**	$ 126,306	$ 179,031	**$ 522,687**	$ 3,311,226
Bank loan (3)	**$ 256,749**	$ 208,195	$ 666,886	**$ 256,749**	$ 666,886
Long-term notes (3)	**1,623,658**	1,581,002	1,418,685	**1,623,658**	1,418,685
Long-term debt	**1,880,407**	1,789,197	2,085,571	**1,880,407**	2,085,571
Working capital deficiency	**169,498**	160,539	210,409	**169,498**	210,409
Net debt (4)	**$ 2,049,905**	$ 1,949,736	$ 2,295,980	**$ 2,049,905**	$ 2,295,980

	Three Months Ended			Years Ended	
	December 31, 2015	September 30, 2015	December 31, 2014	**December 31, 2015**	December 31, 2014
OPERATING					
Daily production					
Heavy oil (bbl/d)	**31,733**	33,639	43,186	**34,974**	45,022
Light oil and condensate (bbl/d)	**24,930**	24,712	26,916	**25,887**	17,681
NGL (bbl/d)	**8,996**	8,507	8,098	**8,492**	4,819
Total oil and NGL (bbl/d)	**65,659**	66,858	78,200	**69,353**	67,522
Natural gas (mcf/d)	**92,708**	91,869	84,428	**91,766**	65,234
Oil equivalent (boe/d @ 6:1) (5)	**81,110**	82,170	92,271	**84,648**	78,395
Average prices (before hedging)					
WTI oil (US$/bbl)	**42.18**	46.43	73.14	**48.79**	92.97
WCS Heavy Oil (US$/bbl)	**27.69**	33.13	58.90	**35.26**	73.58
Edmonton par oil ($/bbl)	**52.94**	56.22	75.69	**57.20**	95.28
LLS oil (US$/bbl)	**43.33**	49.79	76.34	**51.50**	96.76
BTE heavy oil ($/bbl) (6)	**24.41**	30.90	53.34	**32.23**	69.64
BTE light oil and condensate ($/bbl)	**50.17**	55.46	77.20	**55.75**	91.37
BTE NGL ($/bbl)	**17.23**	15.35	28.07	**16.91**	35.28
BTE total oil and NGL ($/bbl)	**33.21**	38.00	58.93	**39.13**	72.88
BTE natural gas ($/mcf)	**2.76**	3.28	4.12	**3.08**	4.53
BTE oil equivalent ($/boe)	**30.03**	34.59	53.72	**35.40**	66.54
CAD/USD noon rate at period end	**1.3840**	1.3394	1.1601	**1.3840**	1.1601
CAD/USD average rate for period	**1.3353**	1.3094	1.1378	**1.2811**	1.1050

	Three Months Ended			Years Ended	
	December 31, 2015	September 30, 2015	December 31, 2014	**December 31, 2015**	December 31, 2014
COMMON SHARE INFORMATION					
TSX					
Share price (Cdn$)					
High	**6.88**	19.50	42.90	**24.87**	49.88
Low	**3.50**	3.92	14.56	**3.50**	14.56
Close	**4.48**	4.27	19.32	**4.48**	19.32
Volume traded (thousands)	**283,619**	165,674	133,365	**652,044**	273,743
NYSE					
Share price (US$)					
High	**5.27**	15.51	38.35	**20.10**	46.46
Low	**2.50**	2.92	12.63	**2.50**	12.63
Close	**3.24**	3.20	16.61	**3.24**	16.61
Volume traded (thousands)	**153,763**	109,902	20,255	**375,660**	33,170
Common shares outstanding (thousands)	**210,583**	210,225	168,107	**210,583**	168,107

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 asset retirement obligations settled. 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 capital investments, debt repayment and future dividends. 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, 2015.

(2) Cash dividends declared are net of participation in our dividend reinvestment plan.

(3) Principal amount of instruments.

(4) Net debt is a non-GAAP measure which we define to be the sum of working capital (which is current assets less current liabilities (excluding unrealized gains or losses on financial derivatives)) and the principal amount of long-term debt.

(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

Our operating results for the fourth quarter and full-year 2015 were consistent with our expectations and reflect a reduced pace of drilling activity in response to the low crude oil price environment. Production averaged 81,110 boe/d (81% oil and NGL) in Q4/2015, as compared to 82,170 boe/d (81% oil and NGL) in Q3/2015. For the full-year 2015, production averaged 84,648 boe/d (82% oil and NGL), in line with our production guidance of 84,000 to 86,000 boe/d.

Capital expenditures for exploration and development activities totaled $140.8 million in Q4/2015 and $521.0 million for full-year 2015, in line with our annual guidance of $500 to $575 million. In 2015, we participated in the drilling of 228 (81.6 net) wells with a 99% success rate.

We realized over $150 million in efficiencies in 2015 as we remained focused on cost reduction initiatives across all of our operations. Drilling costs have been reduced by approximately 27% in the Eagle Ford as compared to 2014, operating expenses were reduced by 18% from budget, transportation expenses were reduced by 20% from budget and general and administrative expenses were down 22% from budget.

Wells Drilled - Three Months Ended December 31, 2015

	Crude Oil		**Natural Gas**		**Stratigraphic and Service**		**Dry and Abandoned**		**Total**	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Heavy oil										
Lloydminster	—	—	—	—	—	—	—	—	—	—
Peace River	—	—	—	—	—	—	—	—	—	—
	—	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**
Light oil and natural gas										
Eagle Ford	14	4.1	28	8.5	—	—	—	—	42	12.6
Western Canada	—	—	—	—	—	—	—	—	—	—
	14	**4.1**	**28**	**8.5**	**—**	**—**	**—**	**—**	**42**	**12.6**
Total	**14**	**4.1**	**28**	**8.5**	**—**	**—**	**—**	**—**	**42**	**12.6**

Wells Drilled – Twelve Months Ended December 31, 2015

	Crude Oil		**Natural Gas**		**Stratigraphic and Service**		**Dry and Abandoned**		**Total**	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Heavy oil										
Lloydminster	26	17.4	—	—	1	1.0	—	—	27	18.4
Peace River	6	6.0	—	—	5	5.0	—	—	11	11.0
	32	**23.4**	**—**	**—**	**6**	**6.0**	**—**	**—**	**38**	**29.4**
Light oil and natural gas										
Eagle Ford	66	16.7	119	32.6	1	0.3	2	0.6	188	50.2
Western Canada	—	—	2	2.0	—	—	—	—	2	2.0
	66	**16.7**	**121**	**34.6**	**1**	**0.3**	**2**	**0.6**	**190**	**52.2**
Total	**98**	**40.1**	**121**	**34.6**	**7**	**6.3**	**2**	**0.6**	**228**	**81.6**

Our performance in the Eagle Ford was strong during the fourth quarter as we maintained a consistent pace of development, averaging six drilling rigs and two frac crews on our lands. Production averaged 40,284 boe/d (78% oil and NGL) during Q4/2015, as compared to 38,941 boe/d in Q3/2015 and 39,548 boe/d in Q2/2015. Capital expenditures in the Eagle Ford totaled $132 million during Q4/2015 bringing full-year expenditures to $450 million. As at December 31, 2015, we had 36 (10.1 net) wells waiting on completion.

Significant advancements were made in 2015 to delineate the multi-zone development potential of our Sugarkane acreage. We continued to implement “stack and frac” pilots which target up to three zones in the Eagle Ford formation in addition to the overlying Austin Chalk. In 2015, we drilled 188 (50.2 net) wells on Eagle Ford acreage, of which 56% targeted the Lower Eagle Ford, 26% targeted the Austin Chalk, 11% targeted the Upper Eagle Ford and 7% targeted the upper portion of the Lower Eagle Ford. Recent production data from one pad (a total of 4 wells) that targeted three zones achieved 30-day initial production rates per well ranging from 1,400 to 1,875 boe/d. We currently have thirteen multi-zone projects in various stages of execution and production.

In Q4/2015, we participated in the drilling of 42 (12.6 net) wells in the Eagle Ford and commenced production from 61 (16.6 net) wells. Of the 61 gross wells that commenced production during the fourth quarter, 46 wells have been producing for more than 30 days and have established an average 30-day initial production rate of approximately 1,100 boe/d.

Production in Canada averaged 40,826 boe/d (84% oil and NGL) during Q4/2015, as compared to 43,229 boe/d in Q3/2015. The reduced volumes in Canada are due to the cancellation of the Canadian drilling program as a result of low crude oil prices. Capital expenditures for our Canadian assets in Q4/2015 totaled $8.8 million, a decrease from $33.5 million in Q3/2015.

Financial Review

We generated FFO of $93.1 million ($0.44 per share) in Q4/2015, compared to $105.1 million ($0.51 per share) in Q3/2015. Full-year FFO was $516.4 million ($2.61 per share), compared to $879.8 million ($5.91 per share) in 2014. The decline in FFO is largely due to a decline in commodity prices.

We recorded a net loss in Q4/2015 of $412.9 million ($1.96 per share) compared to a net loss of $517.9 million ($2.49 per share) in Q3/2015. The net loss in the quarter is largely attributable to non-cash impairment charges of $499.6 million ($419.0 million after-tax) related to our Eagle Ford operations and $45.7 million related to assets in Canada. These impairment charges are directly attributable to the decline in commodity prices.

In Q4/2015, the average price for West Texas Intermediate light oil ("WTI") decreased to US$42.18/bbl, as compared to US$46.43/bbl in Q3/2015. This 9% decline in the benchmark index resulted in our realized price for light oil and condensate decreasing 9% to $50.17/bbl. The discount for Canadian heavy oil, as measured by the price differential between Western Canadian Select ("WCS") and WTI, widened to US$14.49/bbl in Q4/2015, as compared to US$13.30/bbl in Q3/2015. The widening differential and lower WTI price resulted in a 16% decrease in the price of WCS and a 21% decrease in our realized heavy oil price to $24.41/bbl.

We generated an operating netback in Q4/2015 of $12.32/boe ($16.41/boe including financial derivatives gains). The Eagle Ford generated an operating netback of $18.77/boe while our Canadian operations generated an operating netback of $5.73/boe. Our Eagle Ford assets are located in south Texas, proximal to Gulf Coast markets, with light oil and condensate production priced off a Louisiana Light Sweet crude oil benchmark which typically trades at a premium to WTI. Declining production in the region has increased competition for field supplies resulting in lower transportation and gathering costs and improved price realizations. This strong pricing, combined with low cash costs, contributed positively to our operating netback in Q4/2015.

During the quarter, we continued to focus on cost reduction initiatives across all of our operations. Operating expenses decreased 25% on a per boe basis as compared to Q4/2014, despite the impact of fixed costs on lower production in Canada. We are also benefiting from the Eagle Ford assets which have lower costs and comprise a larger percentage of our production. Transportation expenses have been reduced by 30% on a per boe basis as compared to Q4/2014, due to overall cost reduction initiatives in Canada, which include the use of internal trucking and decreased fuel charges.

The table below provides a summary of our operating netbacks for the periods noted.

	Three Months Ended December 31				
	2015			2014	
($ per boe)	**Canada**	**Eagle Ford**	**Total**	**Total**	**Change**
Sales price	**$ 23.59**	**$ 36.56**	**$ 30.03**	$ 53.72	(44)%
Other income	**—**	**—**	**0.11**	0.76	(86)%
Less:					
Royalties	**2.72**	**10.56**	**6.61**	11.90	(44)%
Operating expenses	**12.27**	**7.23**	**9.76**	12.95	(25)%
Transportation expenses	**2.87**	**—**	**1.45**	2.07	(30)%
Operating netback	**$ 5.73**	**$ 18.77**	**$ 12.32**	$ 27.56	(55)%
Financial derivatives gain	**—**	**—**	**4.09**	6.48	(37)%
Operating netback after financial derivatives	**$ 5.73**	**$ 18.77**	**$ 16.41**	$ 34.04	(52)%

Risk Management

As part of our normal operations, we are exposed to movements in commodity prices, foreign exchange rates and interest rates. In an effort to manage these exposures, we utilize various financial derivative contracts which are intended to partially reduce the volatility in our FFO. We realized financial derivative gains of $30.4 million in Q4/2015 and $197.5 million for the full-year 2015. These gains were primarily due to crude oil prices being at levels significantly below those set in our fixed price contracts, which were partially offset by the settlement of our foreign exchange contracts.

For 2016, we have entered into hedges on approximately 45% of our net WTI exposure with 19% fixed at US$61.50/bbl and 26% hedged utilizing a 3-way collar structure (as described in the table below). We have also entered into hedges on approximately 35% of our net WCS differential exposure and 41% of our net natural gas exposure. The unrealized financial derivatives gain with respect to our hedges as at February 25, 2016 was $152.2 million. The following table summarizes our hedges in place as at March 3, 2016.

	Q1/2016	Q2/1016	Q3/2016	Q4/2016	Full-Year 2016	Full-Year 2017
CRUDE OIL						
WTI Fixed Hedges						
Volumes (bbl/d)	9,000	8,000	5,000	5,000	6,750	—
Price (US$/bbl)	$60.45	$59.84	$63.79	$63.79	$61.50	—
WTI 3-Way Option						
Volumes (bbl/d)	9,500	9,500	9,500	9,500	9,500	2,000
Average Ceiling/Floor/Sold Floor (US$/bbl) [(2)]	$60/$50/$40	$60/$50/$40	$60/$50/$40	$60/$50/$40	$60/$50/$40	$60/$50/$40
Total WTI Hedge Volumes (bbl/d)	18,500	17,500	14,500	14,500	16,250	2,000
Hedge (%) [(1)]	50%	49%	40%	40%	45%	6%
WCS Differential Hedges						
Volumes (bbl/d)	4,333	8,000	7,000	7,000	6,583	1,500
WCS Price Relative to WTI (US$/bbl)	($13.33)	($13.26)	($13.32)	($13.40)	($13.33)	($13.42)
Hedge % [(1)]	23%	42%	37%	37%	35%	8%
NATURAL GAS						
AECO Fixed Hedges						
Volumes (gj/d)	18,333	20,000	20,000	20,000	19,583	5,000
Price ($/gj)	$2.88	$2.85	$2.85	$2.85	$2.86	$2.81
NYMEX Fixed Hedges						
Volumes (mmbtu/d)	13,333	15,000	15,000	15,000	14,583	10,000
Price (US$/mmbtu)	$3.04	$2.98	$2.98	$2.98	$3.00	$2.83
Total Hedge Volume (mmbtu/d)	30,711	33,975	33,957	33,957	33,146	14,739
Hedge % [(1)]	38%	42%	42%	42%	41%	18%

Notes:

(1) Percentage of hedged volumes is based on the mid-point of our revised 2016 production guidance (excluding NGL), net of royalties.

(2) WTI 3-way option consists of a sold call, a bought put and a sold put. In a $60/$50/$40 example, Baytex receives WTI + US$10/bbl when WTI is at or below US$40/bbl; Baytex receives US$50/bbl when WTI is between US$40/bbl and US$50/bbl; Baytex receives WTI when WTI is between US$50/bbl and US$60/bbl; and Baytex receives US$60/bbl when WTI is above US$60/bbl.

Financial Liquidity

Total long-term debt at December 31, 2015 was $1.88 billion, comprised of a bank loan of $257 million and senior unsecured notes of $1.62 billion. The increase in total long-term debt at December 31, 2015, as compared to September 30, 2015, was primarily due to the amount of our U.S. dollar denominated debt increasing when converted to Canadian dollars.

We have unsecured revolving credit facilities consisting of an $800 million Canadian facility and a US$200 million U.S. facility. As at December 31, 2015, we had approximately $820 million in undrawn capacity on these facilities, which do not mature until June 2019.

Our bank lending syndicate agreed to relax the financial covenants contained in our unsecured revolving credit facilities twice during 2015. In each case, these amendments were obtained pro-actively, as we remained in compliance with our un-amended financial covenants throughout 2015. We will continue to manage our credit facilities and, if the outlook for commodity prices remains low or further deteriorates, we may seek further covenant relief. This could include granting our bank lending syndicate security over our assets. The indentures governing our senior unsecured notes provide that we may secure up to US$575 million of indebtedness in priority to the senior unsecured notes.

The following table lists the covenants under the revolving credit facilities and the senior unsecured notes, and our compliance therewith as at December 31, 2015.

Covenant Description		**Position as at December 31, 2015**
Revolving Credit Facilities – Financial Covenants	**Maximum Ratio**	
Senior Debt to Capitalization[(1) (2)]	0.65:1.00	0.44:1.00
Senior Debt to Bank EBITDA[(1) (5)]	5.25:1.00	2.97:1.00
Total Debt to Bank EBITDA[(3) (5)]	5.25:1.00	2.97:1.00
Senior Unsecured Notes – Debt Incurrence Covenant	**Minimum Ratio**	
Fixed Charge Coverage[(4)]	2.50:1.00	5.63:1.00

Notes:

(1) "Senior debt" is defined as our principal amount of bank loan and long-term notes.
(2) "Capitalization" is defined as the sum of our principal amount of bank loan and long-term notes and shareholders' equity.
(3) "Total debt" is defined as the sum of our principal amount of bank loan and long-term notes, and certain other liabilities identified in the credit agreement.
(4) Fixed charge coverage is computed as the ratio of financing costs (excluding accretion on asset retirement obligations) to trailing twelve month adjusted income, as defined in the note indentures. Adjusted income for the trailing twelve months ended December 31, 2015 was $629 million.
(5) 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.

Outlook for 2016

As an industry, we continue to face unprecedented challenges due to the continued global oversupply of crude oil. We are committed to preserving financial liquidity through this downturn. In 2016, we are targeting capital expenditures to approximate funds from operations in order to minimize additional bank borrowings. In addition, we may contemplate minor non-core asset sales.

Our original 2016 production guidance was 74,000 to 78,000 boe/d with budgeted exploration and development expenditures of $325 to $400 million. This budget contemplated ramping up activity in Canada in the second half of 2016.

Based on the forward strip for the remainder of 2016, we do not plan to execute our heavy oil development program this year. We will forgo drilling 12 net wells at Peace River and 24 net wells at Lloydminster. In addition, we are proactively shutting-in approximately 7,500 bbl/d of low or negative margin heavy oil production in order to optimize the value of our resource base and maximize our funds from operations. Should netbacks improve, we have the ability to restart these wells within one month. We currently anticipate that this production will be brought back on-line mid-year.

In the Eagle Ford, we now anticipate a reduced pace of development in 2016 with approximately four to five drilling rigs (six drilling rigs in Q4/2015) and one to two frac crews (two frac crews in Q4/2015) working on our lands. At this pace, we anticipate bringing approximately 30 net wells on production in 2016 (previously 35 to 40 net wells).

We now anticipate 2016 exploration and development expenditures of $225 to $265 million, of which approximately 95% will be invested in the Eagle Ford. At the mid-point, this reflects a 33% reduction in capital spending for 2016 relative to our initial expectation of $325 to $400 million and a 53% reduction relative to 2015 capital expenditures of $521 million. Our 2016 program will remain flexible and allows for adjustments to spending based on changes in the commodity price environment.

Taking into account the shut-in heavy oil volumes and a reduced capital program, we have revised our production guidance range for 2016 to 68,000 to 72,000 boe/d. Our revised production guidance represents an approximate 5% reduction to our original guidance, excluding the impact of shut-in volumes. This compares to a 33% reduction in our capital budget, demonstrating the continued strong performance of our assets. Based on the mid-point of our production guidance range, approximately 55% of our production is expected to be generated in the Eagle Ford with the remaining 45% coming from our Canadian assets.

Production during the first quarter of 2016 is expected to average 73,000 to 75,000 boe/d.

Year-end 2015 Reserves

Baytex's year-end 2015 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 December 31, 2015 forecast price and cost assumptions. Ryder Scott also evaluated 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, 2015, which will be filed on or before March 30, 2016.

2015 Highlights

The addition of the Eagle Ford assets to our portfolio in 2014 provided us with exposure to one of the premier oil resource plays in North America. The high quality Eagle Ford assets provide the highest cash netbacks in our portfolio and contain a significant inventory of development prospects. In 2015, we focused our development activity in the Eagle Ford, where we directed 86% of our exploration and development expenditures. Our 2015 reserves report reflect this investment profile with significant growth in Eagle Ford reserves, offset by reduced heavy oil and thermal reserves.

- Excluding thermal reductions, our proved plus probable reserves increased 2% to 347 mmboe and we replaced 122% of production. Year-end 2015 proved plus probable reserves are comprised of 81% oil and NGL and 19% natural gas.

- In the Eagle Ford, proved plus probable reserves increased 8% to 203 mmboe and we replaced 205% of production. From the time of acquisition in June 2014, we have increased our proved plus probable reserves by 22%.

- In aggregate, proved reserves decreased 3% to 275 mmboe and proved plus probable reserves decreased 3% to 417 mmboe, due largely to shifting thermal reserves to contingent resources at Cliffdale as activities fall outside our five year investment plan and the removal of heavy oil reserves due to reduced commodity prices and other technical revisions.

- Proved developed producing ("PDP") reserves represent 40% of our proved reserves (versus 43% at year-end 2014) and proved reserves represent 66% of proved plus probable reserves (unchanged from year-end 2014).

- We realized F&D costs of $7.68/boe on a proved plus probable basis, and a three-year average (2013-2015) of $17.59/boe. Based on our 2015 operating netback (excluding financial derivative gains) of $15.78/boe, we generated a strong recycle ratio of 2.1x in 2015.

- We realized FD&A costs of $7.75/boe on a proved plus probable basis, and a three-year average (2013-2015) of $26.33/boe. Based on our 2015 operating netback (excluding financial derivative gains) of $15.78/boe, we generated a strong recycle ratio of 2.0x in 2015.

- We achieved a significant reduction in our future development costs from $3.4 billion at year-end 2014 to $3.0 billion at year-end 2015. This was mainly attributable to decrease in drilling, completions and facility capital costs, as well as the removal of capital associated with a reduction in our thermal reserves.

- Strong reserves life index ("RLI") of 9.3 years on a proved basis and 14.1 years on a proved plus probable basis, which is calculated using annualized Q4/2015 production.

- Using the December 31, 2015 independent reserves evaluation, the present value of our reserves, discounted at 10% before tax, is estimated to be $4.3 billion.

- Our estimated net asset value at year-end 2015, discounted at 10%, is estimated to be $11.05 per share. This is based on the estimated reserves value of $4.3 billion plus a value for undeveloped acreage, net of long-term debt, asset retirement obligations and working capital.

The following tables reconcile the change in reserves during 2015 by reserves category and operating area.

(gross reserves, mmboe)	Eagle Ford	Heavy Oil	Canada Conventional	Total Excluding Thermal	Thermal	Total
Proved Developed Producing						
December 31, 2014	54.8	45.2	10.9	110.9	9.8	120.7
Additions, net of revisions	20.1	4.4	2.8	27.3	(8.4)	18.8
Production	(14.6)	(12.4)	(3.1)	(30.1)	(0.9)	(30.9)
December 31, 2015	60.3	37.2	10.6	108.1	0.5	108.6
% Change	10%	(18%)	(3%)	(3%)	(95%)	(10%)
Proved						
December 31, 2014	167.3	81.5	16.4	265.2	18.1	283.3
Additions, net of revisions	22.2	(0.7)	4.3	25.8	(3.4)	22.4
Production	(14.6)	(12.4)	(3.1)	(30.1)	(0.9)	(30.9)
December 31, 2015	174.9	68.4	17.6	260.9	13.8	274.8
% Change	5%	(16%)	7%	(2%)	(24%)	(3%)
Proved Plus Probable						
December 31, 2014	188.0	122.1	30.4	340.5	91.1	431.6
Additions, net of revisions	29.9	(2.9)	9.5	36.5	(20.6)	15.9
Production	(14.6)	(12.4)	(3.1)	(30.1)	(0.9)	(30.9)
December 31, 2015	203.4	106.8	36.8	347.0	69.6	416.6
% Change	8%	(13%)	21%	2%	(24%)	(3%)

Eagle Ford

- The success of our 2015 capital development program and the significant advancements made to delineate the multi-zone development potential of our Sugarkane acreage, resulted in strong reserves additions in the Eagle Ford. In the Eagle Ford, we replaced 205% of production, and increased our proved plus probable reserves by 8% to 203.4 mmboe.

- Ryder Scott assigned a total of 184 net proved undeveloped and probable well locations in the year-end reserves report. Approximately 87% of the well locations are targeting the Lower Eagle Ford formation with the remainder attributable to the Austin Chalk. We have not assigned any undeveloped locations to the Upper Eagle Ford formation in our proved plus probable reserves.

- In addition to our proved plus probable reserves, we have recognized 144 mmboe of possible reserves. 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. There is a 10% probability that the quantities actually recovered will equal or exceed the sum of proved plus probable plus possible reserves

Heavy Oil

- Reserves associated with our heavy oil assets are located at Peace River and Lloydminster. Proved plus probable heavy oil reserves at year-end 2015 totalled 106.8 mmboe, down 13% from 122.1 mmboe at year-end 2014. In 2015, our development activity was significantly curtailed due to low crude oil prices. At Peace River, we drilled 6 (6.0 net) cold horizontal production wells and 5 (5.0 net) stratigraphic test wells. At Lloydminster, we drilled 26 (17.4 net) oil wells.

- We realized 7.5 mmboe of reserves additions at Peace River and Lloydminster in 2015. These reserves additions were offset by the removal of reserves due to the decrease in commodity prices since year-end 2014 and other technical revisions. On a proved plus probable basis, negative technical revisions amounted to 6.9 mmboe and a further 3.6 mmboe were removed due to lower commodity prices.

Conventional - Canada

- Reserves associated with our conventional light oil and natural gas assets in Canada increased 21% to 36.8 mmboe, resulting in production replacement of 306%. Reserves additions were driven by strong well performance and the identification of additional drilling locations from our liquids-rich natural gas development in the Pembina/O'Chiese region of west-central Alberta.

Bitumen (Thermal)

- Reserves associated with our thermal heavy oil projects at Peace River, Gemini (Cold Lake) and Kerrobert are classified as bitumen, in accordance with NI 51-101. Proved plus probable bitumen reserves at year-end 2015 totalled 69.6 mmbbls, down 24% from 91.1 mmbbls at year-end 2014, and now represent 17% of our proved plus probable reserves, compared to 21% at year-end 2014 and 32% at year-end 2013.

- During the third quarter of 2015, as crude oil prices continued to deteriorate, we suspended operations at our Cliffdale Cyclical Steam Stimulation project. With no production at Cliffdale at year-end 2015, 7.0 mmbbls of proved developed producing reserves were reclassified as proved developed non-producing. In addition, we transferred 19.3 mmbbls of proved plus probable reserves associated with Pads 3 and 4 to contingent resources as this development is now expected to occur outside our five-year business plan.

- At Gemini, we decommissioned our steam-assisted gravity drainage pilot project in the second quarter of 2015. Through the pilot we confirmed reservoir production capacity to support a commercial 5,000 bbl/d project. Any subsequent sanctioning decision will be considered in the context of the project economics in a higher commodity price environment. Our proved plus probable bitumen reserves at Gemini were unchanged at year-end 2015 at 43.4 mmbbls.

Petroleum and Natural Gas Reserves as at December 31, 2015

The following table sets forth our gross and net reserves volumes at December 31, 2015 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	34,199	25,847	529	485	2,758	2,522
Developed Non-Producing	3,469	2,910	7,801	6,917	45	40
Undeveloped	27,362	22,498	5,429	4,522	99	118
Total Proved	65,030	51,254	13,758	11,925	2,902	2,681
Probable	37,883	29,642	55,882	43,421	2,420	2,100
Total Proved Plus Probable	102,913	80,896	69,640	55,346	5,323	4,781

CANADA	Forecast Prices and Costs					
	Natural Gas Liquids		Conventional 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	1,364	1,005	56,397	46,976	48,248	37,688
Developed Non-Producing	4	3	349	327	11,377	9,925
Undeveloped	1,376	1,089	35,254	29,511	40,142	33,145
Total Proved	2,745	2,096	92,000	76,814	99,767	80,758
Probable	3,081	2,285	85,538	70,169	113,523	89,143
Total Proved Plus Probable	5,826	4,381	177,538	146,982	213,290	169,900

UNITED STATES	Forecast Prices and Costs					
	Tight 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	20,403	15,003	25,812	19,072	56,753	41,948
Developed Non-Producing	—	—	—	—	—	—
Undeveloped	28,812	21,155	57,897	42,491	138,014	101,130
Total Proved	49,215	36,158	83,710	61,563	194,767	143,078
Probable	4,551	3,343	16,263	11,904	40,038	29,357
Total Proved Plus Probable	53,765	39,501	99,972	73,467	234,805	172,435
Possible[4][5]	16,920	12,505	88,902	65,436	210,894	155,206
Total Proved Plus Probable Plus Possible	70,685	52,006	188,874	138,903	445,699	327,641

UNITED STATES

	Forecast Prices and Costs			
	Conventional Natural Gas		Oil Equivalent[3]	
Reserves Category	Gross[1] (mmcf)	Net[2] (mmcf)	Gross[1] (mboe)	Net[2] (mbbl)
Proved				
Developed Producing	27,859	20,502	60,317	44,483
Developed Non-Producing	—	—	—	—
Undeveloped	29,021	21,330	114,548	84,056
Total Proved	56,880	41,832	174,865	128,539
Probable	5,991	4,406	28,486	20,874
Total Proved Plus Probable	62,871	46,238	203,350	149,413
Possible[4][5]	20,049	14,799	144,312	106,276
Total Proved Plus Probable Plus Possible	82,920	61,037	347,662	255,689

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	34,199	25,847	529	485	2,758	2,522
Developed Non-Producing	3,469	2,910	7,801	6,917	45	40
Undeveloped	27,362	22,498	5,429	4,522	99	118
Total Proved	65,030	51,254	13,758	11,925	2,902	2,681
Probable	37,883	29,642	55,882	43,421	2,420	2,100
Total Proved Plus Probable	102,913	80,896	69,640	55,346	5,323	4,781
Possible[4][5]	—	—	—	—	—	—
Total Proved Plus Probable Plus Possible	102,913	80,896	69,640	55,346	5,323	4,781

TOTAL

	Forecast Prices and Costs					
	Tight 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	20,403	15,003	27,176	20,077	56,753	41,948
Developed Non-Producing	—	—	4	3	—	—
Undeveloped	28,812	21,155	59,273	43,580	138,014	101,130
Total Proved	49,215	36,158	86,454	63,659	194,767	143,078
Probable	4,551	3,343	19,344	14,188	40,038	29,357
Total Proved Plus Probable	53,765	39,501	105,798	77,848	234,805	172,435
Possible[4][5]	16,920	12,505	88,902	65,436	210,894	155,206
Total Proved Plus Probable Plus Possible	70,685	52,006	194,699	143,284	445,699	327,641

TOTAL	**Forecast Prices and Costs**			
	Conventional Natural Gas		**Oil Equivalent[3]**	
Reserves Category	**Gross[1] (mmcf)**	**Net[2] (mmcf)**	**Gross[1] (mboe)**	**Net[2] (mboe)**
Proved				
Developed Producing	84,256	67,477	108,565	82,171
Developed Non-Producing	349	327	11,377	9,925
Undeveloped	64,275	50,841	154,690	117,201
Total Proved	148,880	118,646	274,633	209,297
Probable	91,530	74,575	142,008	110,017
Total Proved Plus Probable	240,409	193,220	416,640	319,313
Possible[4][5]	20,049	14,799	144,312	106,276
Total Proved Plus Probable Plus Possible	260,458	208,019	560,952	425,589

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 (1)(2)
By Principal Product Type
Forecast Prices and Costs

Gross Reserves Category	Heavy Oil Proved (mbbl)	Heavy Oil Probable (mbbl)	Heavy Oil Proved + Probable (mbbl)	Bitumen Proved (mbbl)	Bitumen Probable (mbbl)	Bitumen Proved + Probable (mbbl)
December 31, 2014	78,145	39,777	117,922	18,058	73,054	91,112
Extensions	1,121	4,592	5,713	—	—	—
Infill Drilling	929	620	1,549	—	—	—
Improved Recoveries	—	175	175	—	—	—
Technical Revisions	(475)	(6,677)	(7,151)	(3,225)	(17,194)	(20,419)
Discoveries	11	4	15	—	—	—
Acquisitions	1,515	511	2,026	—	—	—
Dispositions	(977)	(922)	(1,900)	—	—	—
Economic Factors	(3,341)	(196)	(3,537)	(211)	22	(189)
Production	(11,898)	—	(11,898)	(864)	—	(864)
December 31, 2015	65,030	37,883	102,913	13,758	55,882	69,640

Gross Reserves Category	Light and Medium Crude Oil Proved (mbbl)	Light and Medium Crude Oil Probable (mbbl)	Light and Medium Crude Oil Proved + Probable (mbbl)	Tight Oil Proved (mbbl)	Tight Oil Probable (mbbl)	Tight Oil Proved + Probable (mbbl)
December 31, 2014	3,736	2,496	6,232	49,333	4,546	53,879
Extensions	—	—	—	—	—	—
Infill Drilling	1	—	1	4,971	473	5,444
Improved Recoveries	—	—	—	—	—	—
Technical Revisions	347	(333)	15	989	(328)	661
Discoveries	—	—	—	—	—	—
Acquisitions	—	—	—	—	—	—
Dispositions	—	—	—	—	—	—
Economic Factors	(521)	257	(265)	(457)	(140)	(597)
Production	(660)	—	(660)	(5,622)	—	(5,622)
December 31, 2015	2,902	2,420	5,323	49,215	4,551	53,765

Gross Reserves Category	Natural Gas Liquids Proved (mbbl)	Natural Gas Liquids Probable (mbbl)	Natural Gas Liquids Proved + Probable (mbbl)	Shale Gas Proved (mmcf)	Shale Gas Probable (mmcf)	Shale Gas Proved + Probable (mmcf)
December 31, 2014	81,583	12,753	94,336	185,604	22,543	208,147
Extensions	49	428	477	—	—	—
Infill Drilling	13,339	9,152	22,491	28,783	22,560	51,342
Improved Recoveries	—	—	—	—	—	—
Technical Revisions	(1,740)	(2,871)	(4,611)	(7,017)	(4,759)	(11,776)
Discoveries	—	—	—	—	—	—
Acquisitions	—	—	—	—	—	—
Dispositions	—	—	—	—	—	—
Economic Factors	(521)	(119)	(640)	(762)	(305)	(1,067)
Production	(6,256)	—	(6,256)	(11,841)	—	(11,841)
December 31, 2015	86,454	19,344	105,798	194,767	40,038	234,805

Gross Reserves Category	Conventional Natural Gas Proved (mmcf)	Conventional Natural Gas Probable (mmcf)	Conventional Natural Gas Proved + Probable (mmcf)	Oil Equivalent(3) Proved (mboe)	Oil Equivalent(3) Probable (mboe)	Oil Equivalent(3) Proved + Probable (mboe)
December 31, 2014	128,762	71,891	200,653	283,249	148,365	431,614
Extensions	1,263	10,107	11,369	1,381	6,704	8,085
Infill Drilling	8,573	1,463	10,036	25,465	14,249	39,714
Improved Recoveries	—	—	—	—	175	175
Technical Revisions	38,990	10,593	49,583	1,225	(26,430)	(25,204)
Discoveries	—	—	—	11	4	15
Acquisitions	—	—	—	1,515	511	2,026
Dispositions	—	—	—	(977)	(922)	(1,900)
Economic Factors	(7,057)	(2,525)	(9,582)	(6,354)	(648)	(7,002)
Production	(21,651)	—	(21,651)	(30,882)	—	(30,882)
December 31, 2015	148,880	91,529	240,409	274,633	142,008	416,640

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) Reserves information as at December 31, 2015 and 2014 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 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.

Reserves Life Index

The following table sets forth our reserves life index, which is calculated by dividing our proved and proved plus probable reserves at year-end 2015 by Q4/2015 production.

	Q4/2015 Actual Production	Reserves Life Index (years) Proved	Reserves Life Index (years) Proved Plus Probable
Oil and NGL (bbl/d)	65,659	9.1	14.1
Natural Gas (mcf/d)	92,708	10.2	14.0
Oil Equivalent (boe/d)	81,110	9.3	14.1

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.

	2015	2014	2013	Three-Year Total / Average 2013 - 2015
Capital Expenditures ($ millions)				
Exploration and development	$ 521.0	$ 766.1	$ 550.9	$ 1,838.0
Acquisitions (net of dispositions)	1.6	2,545.1	(39.1)	2,507.7
Total	$ 522.7	$ 3,311.2	$ 511.8	$ 4,345.7
Change in Future Development Costs – Proved ($ millions)				
Exploration and development	$ (397.9)	$ (248.5)	$ 300.8	$ (345.6)
Acquisitions (net of dispositions)	6.0	1,312.9	(39.3)	1,279.6
Total	$ (391.9)	$ 1,064.4	$ 261.5	$ 934.0
Change in Future Development Costs – Proved plus Probable ($ millions)				
Exploration and Development	$ (399.9)	$ (102.0)	$ 393.7	$ (108.2)
Acquisitions (net of dispositions)	0.5	1,210.5	(39.3)	1,171.7
Total	$ (399.4)	$ 1,108.5	$ 354.4	$ 1,063.5
Proved Reserves Additions (mboe)				
Exploration and development	21,729	83,515	38,117	143,362
Acquisitions (net of dispositions)	537	68,824	(1,160)	68,201
Total	22,266	152,339	36,957	211,563
Proved plus Probable Reserves Additions (mboe)				
Exploration and development	15,782	33,598	48,936	98,316
Acquisitions (net of dispositions)	126	108,515	(1,540)	107,101
Total	15,908	142,113	47,396	205,417
F&D costs ($/boe) (1)				
Proved	$ 5.67	$ 6.20	$ 22.34	**$** 10.41
Proved plus probable	$ 7.68	$ 19.77	$ 19.30	**$** 17.59
FD&A costs ($/boe) (2)				
Proved	$ 5.88	$ 28.72	$ 20.92	**$** 24.96
Proved plus probable	$ 7.75	$ 31.10	$ 18.28	**$** 26.33
Ratios (based on proved plus probable reserves)				
Production replacement (3)	52%	497%	227%	255%
Recycle ratio (4)	2.1x	1.8x	1.7x	1.9x

Notes:

(1) F&D costs are calculated as total exploration and development expenditures (excluding acquisition and divestitures) divided by reserves additions from exploration and development activity.

(2) FD&A costs are calculated as total capital expenditures (including acquisition and divestitures) divided by total reserves additions.

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

(4) 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, 2015
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	$ 708,303	$ 611,709	$ 534,278	$ 473,010	$ 424,180
Developed Non-Producing	305,817	210,792	150,901	111,743	85,246
Undeveloped	738,519	537,449	397,466	297,941	225,503
Total Proved	1,752,639	1,359,950	1,082,644	882,694	734,929
Probable	2,621,469	1,437,508	875,496	573,723	395,191
Total Proved Plus Probable	$ 4,374,108	$ 2,797,458	$ 1,958,141	$ 1,456,417	$ 1,130,120

UNITED STATES

Reserves Category	0% ($000s)	5% ($000s)	10% ($000s)	15% ($000s)	20% ($000s)
Proved					
Developed Producing	$ 1,696,780	$ 1,283,191	$ 1,027,554	$ 857,701	$ 738,088
Developed Non-Producing					
Undeveloped	2,596,337	1,661,238	1,108,896	761,605	532,125
Total Proved	4,293,117	2,944,429	2,136,450	1,619,306	1,270,213
Probable	830,523	400,056	216,176	127,677	80,458
Total Proved Plus Probable	5,123,640	3,344,485	2,352,627	1,746,984	1,350,670
Possible (1)	3,899,317	2,447,383	1,659,634	1,186,615	880,408
Total Proved Plus Probable Plus Possible (1)	$ 9,022,957	$ 5,791,868	$ 4,012,261	$ 2,933,599	$ 2,231,078

TOTAL

Reserves Category	0% ($000s)	5% ($000s)	10% ($000s)	15% ($000s)	20% ($000s)
Proved					
Developed Producing	$ 2,405,083	$ 1,894,899	$ 1,561,832	$ 1,330,711	$ 1,162,267
Developed Non-Producing	305,817	210,792	150,901	111,743	85,246
Undeveloped	3,334,856	2,198,688	1,506,362	1,059,546	757,628
Total Proved	6,045,756	4,304,379	3,219,095	2,502,000	2,005,142
Probable	3,451,992	1,837,564	1,091,673	701,400	475,648
Total Proved Plus Probable	9,497,748	6,141,943	4,310,767	3,203,401	2,480,790
Possible (1)(2)	3,899,317	2,447,383	1,659,634	1,186,615	880,408
Total Proved Plus Probable Plus Possible (1)(2)	$ 13,397,065	$ 8,589,326	$ 5,970,402	$ 4,390,016	$ 3,361,198

(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 Forecast Prices and Costs

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, 2015.

Year	WTI Cushing US$/bbl	Canadian Light Sweet C$/bbl	Western Canada Select C$/bbl	Henry Hub US$/MMbtu	AECO-C Spot C$/MMbtu	Operating Cost Inflation Rate %/Yr	Capital Cost Inflation Rate %/Yr	Exchange Rate $US/$Cdn
2015 act.	48.80	57.45	46.09	2.63	2.70	1.4	(19.7)	0.783
2016	45.00	55.20	45.26	2.25	2.25	0.0	0.0	0.750
2017	60.00	69.00	57.96	3.00	2.95	0.0	4.0	0.800
2018	70.00	78.43	65.88	3.50	3.42	1.5	4.0	0.830
2019	80.00	89.41	75.11	4.00	3.91	1.5	4.0	0.850
2020	81.20	91.71	77.03	4.25	4.20	1.5	1.5	0.850
2021	82.42	93.08	78.19	4.31	4.28	1.5	1.5	0.850
2022	83.65	94.48	79.36	4.38	4.35	1.5	1.5	0.850
2023	84.91	95.90	80.55	4.44	4.43	1.5	1.5	0.850
2024	86.18	97.34	81.76	4.51	4.51	1.5	1.5	0.850
2025	87.48	98.80	82.99	4.58	4.59	1.5	1.5	0.850
2026	88.79	100.28	84.23	4.65	4.67	1.5	1.5	0.850
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)
2016	$ 61,711	$ 85,939
2017	178,007	225,264
2018	161,646	359,531
2019	50,505	236,404
2020	12,469	113,829
Remaining	19,602	319,189
Total (Undiscounted)	$ 483,940	$ 1,340,155

UNITED STATES Year	Proved Reserves ($000s)	Proved Plus Probable Reserves ($000s)
2016	$ 157,342	$ 167,145
2017	256,592	267,412
2018	224,399	271,612
2019	518,791	540,938
2020	319,128	351,414
Remaining	26,531	37,251
Total (Undiscounted)	$ 1,502,783	$ 1,635,772

TOTAL Year	Proved Reserves ($000s)	Proved Plus Probable Reserves ($000s)
2016	$ 219,053	$ 253,084
2017	434,599	492,676
2018	386,045	631,143
2019	569,297	777,342
2020	331,597	465,243
Remaining	46,133	356,440
Total (Undiscounted)	$ 1,986,723	$ 2,975,927

Undeveloped Land Holdings

The following table sets forth our undeveloped land holdings as at December 31, 2015.

	Undeveloped Acres	
	Gross	**Net**
Canada		
Alberta	580,616	513,765
British Columbia	660	26
Saskatchewan	139,163	132,990
Total Canada	720,438	646,781
United States		
Texas	10,855	8,409
Total Company	731,294	655,190

We estimate the value of our net undeveloped land holdings at December 31, 2015 to be approximately $110 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.

Net Asset Value

Our estimated net asset value is based on the estimated net present value of all future net revenue from our reserves, before tax, as estimated by the Company's independent reserves engineers, Sproule and Ryder Scott, at year-end, plus the estimated value of our undeveloped acreage, less asset retirement obligations, long-term debt and net working capital. This calculation can vary significantly depending on the oil and natural gas price assumptions used by the independent reserves evaluators.

In addition, this calculation does not consider "going concern" value and assumes only the reserves identified in the reserves reports with no further acquisitions or incremental development, including development of possible reserves or contingent resources. As we execute our capital programs, we expect to convert possible reserves and contingent resources to reserves which could result in an increase in booked proved plus probable reserves.

The following table sets forth our net asset value as at December 31, 2015.

	Net Asset Value – Forecast Prices and Costs (before tax)				
($ millions except share amounts, discounted at)	**0%**	**5%**	**10%**	**15%**	**20%**
Total net present value of proved plus probable reserves (before tax)	$ 9,498	$ 6,142	$ 4,311	$ 3,203	$ 2,481
Undeveloped acreage (1)	110	110	110	110	110
Asset retirement obligations (2)	(425)	(104)	(44)	(30)	(32)
Long–term debt	(1,880)	(1,880)	(1,880)	(1,880)	(1,880)
Net working capital	(170)	(170)	(170)	(170)	(170)
Net Asset Value	$ 7,133	$ 4,098	$ 2,327	$ 1,233	$ 541
Net Asset Value per Share (3)	$ 33.87	$ 19.46	$ 11.05	$ 5.85	$ 2.42

(1) Undeveloped acreage value generally represents the estimated replacement cost of our undeveloped land.
(2) Asset retirement obligations may not equal the amount shown on the statement of financial position as a portion of these costs are already reflected in the present value of proved plus probable reserves and the discount rates applied differ.
(3) Based on 210.6 million common shares outstanding as at December 31, 2015.

Contingent Resources Assessment

We commissioned Sproule to conduct an evaluation of our contingent resources in the Peace River Area and certain properties in Northeast Alberta. We also commissioned Ryder Scott to conduct an audit of our internal evaluation of our contingent resources in the Eagle Ford Area of Texas. Both assessments were effective December 31, 2015, and were prepared in accordance with the Canadian definitions, standards and procedures contained in the COGE Handbook and NI 51-101.

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.

The contingent resources described below represent our gross interests and are a best estimate. A "best estimate" is considered to be the best estimate of the quantity of resources that will actually be recovered. It is equally likely that the actual quantities recovered will be greater or less than the best estimate. Those resources identified in the best estimate have a 50% probability that the actual quantities recovered will equal or exceed the estimate. The contingent resources herein are presented as deterministic cumulative best estimate volumes.

Our contingent resources fall within the development pending and development unclarified sub-classes, which are defined as follows:

- Development Pending – are economic contingent resources that have a high chance of development. Contingencies are directly influenced by the developer, are actively being pursued and resolution is expected in a reasonable time period.
- Development Unclarified – are contingent resources that have a chance of development which is difficult to assess, and have an economic status which is undetermined. Projects are currently under evaluation and therefore contingencies are not clearly defined. Progress is expected within a reasonable time period.

Development Pending

The following table presents the company gross best estimate of our contingent resources for the assessed properties that fall within the development pending project maturity sub-class, using Sproule's December 31, 2015 forecast prices and costs.

Development Pending (Best Estimate) [(1)]

	Unrisked (mmboe)	Chance of Development	Risked (mmboe)	Risked NPV Discounted at 10% (before tax) ($MM)
Canada				
Peace River	19	81%	16	$90
Northeast Alberta	3	86%	3	$10
Total Canada	23		19	$100
United States				
Eagle Ford	74	80%	59	$459
Total Company	96		78	$560

(1) Numbers may not add due to rounding.

The estimates of risked net present value ("NPV") of future net revenues of the development pending contingent resources are preliminary assessments and are provided to assist the reader in reaching an opinion on the quality of the resources and likelihood of our proceeding with the required investment. It includes contingent resources that are considered too uncertain with respect to the chance of development to be classified as reserves. There is uncertainty that the risked NPV of future net revenue will be realized.

The following table summarizes the status of our risked development pending contingent resources.

Development Pending – Status

	Product Type	Project Status	Capital to reach Commercial Production(1)	Timing of First Commercial Production	Recovery Technology
Peace River	Bitumen	Pre-Development	$136	2019-2021	CSS
Northeast Alberta	Heavy Oil	Pre-Development	$54	2021-2027	Horizontal drilling and cold production methods
Eagle Ford	Tight Oil, Shale Gas and NGL	Pre-Development	$1,114	2016-2024	Horizontal multi-stage fracturing and production operations

(1) Un-risked capital.

The principal risks that would influence the development of the Peace River and Northeast Alberta development pending contingent resources are: the timing of regulatory approvals to expand the project areas, the results of delineation drilling and seismic activity necessary for project development, the ability of these projects to compete for capital against our other projects, our corporate commitment to the timing of development, and the commodity price levels affecting the economic viability bitumen and heavy oil production in Alberta. The principal risks specific to the development of the Eagle Ford development pending contingent resources are: our reliance on the Operator's commitment of capital and timing to the development, the ability of these projects to compete for capital against our other projects, and the possibility of inter-well communication from infill drilling.

Development Unclarified

Our development unclarified contingent resources are conceptual project scenarios with no specific company defined development plan in the near term. The following table presents the company gross best estimate of our contingent resources for the assessed properties that fall within the development unclarified project maturity sub-classes.

Development Unclarified (Best Estimate) (1)

	Unrisked (mmboe)	Chance of Development	Risked (mmboe)
Canada			
Peace River	813	61%	492
Northeast Alberta	141	48%	68
Total Canada	954		560
United States			
Eagle Ford	61	50%	31
Total Company	1,015		590

(1) Numbers may not add due to rounding.

In addition to the risks identified for the development pending sub-class, the projects in the Peace River and Northeast Alberta development unclarified sub-class are also subject to risks pertaining to commercial productivity of the reservoirs. The geological complexity and variability in these reservoirs may require the implementation of pilot projects to test the viability of SAGD and CSS recovery technologies. The risks outlined for the contingent resources in the Eagle Ford development pending sub-class also apply to the development unclarified sub-class but are greater in magnitude.

Additional disclosures related to our contingent resources will be included in Appendix A to our Annual Information Form for the year ended December 31, 2015, which will be filed on or before March 30, 2016.

Additional Information

Our audited consolidated financial statements for the year ended December 31, 2015 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 3, 2016, starting at 9:00am MST (11:00am EST). To participate, please dial 416-340-2219 or toll free in North America 1-866-225-2055 and toll free international 1-800-6578-9868. Alternatively, to listen to the conference call online, please enter http://www.gowebcasting.com/7259 in your web browser.

An archived recording of the conference call will be available until March 10, 2016 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 9337255. 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 but not limited to: our business strategies, plans and objectives; our exploration and development capital budget for 2016; our plan to shut-in certain heavy oil production, our belief that this action will preserve the value of our resource base and maximize our funds from operations and our expectations for the period of time that such production will remain shut-in and the time required to re-start such production; our Eagle Ford shale play, including our assessment of the performance of wells drilled in the Eagle Ford in 2015, initial production rates from new wells, 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; the existence, operation and strategy of our risk management program for commodity prices, heavy oil differentials and interest and foreign exchange rates; the proportion of our anticipated oil and gas production that is hedged and the effectiveness of such hedges in protecting our funds from operations; our liquidity and financial capacity; expectations regarding our ability to comply with the financial covenants under our revolving credit facilities and senior unsecured notes; the possibility that we may seek further covenant relief from, and grant security over our assets to, our bank lending syndicate; our target for 2016 capital expenditures to approximate funds from operations in order to minimize additional bank borrowings; the possibility of non-core asset sales; our expectations for annual average production rate and exploration and development capital budget for 2016 (both original and revised); our expectation that we will not proceed with our 2016 heavy oil development program; the number of drilling rigs and frac crews working on our Eagle Ford lands during 2016; the portion of our 2016 capital budget to be invested in the Eagle Ford; the number of net wells to be brought on production in the Eagle Ford during 2016; the geographic breakdown of our 2016 annual production; our expectations for the average production rate in Q1/2016; the number of net proved undeveloped and probable well locations in the Eagle Ford assigned by our independent reserves evaluator; our reserves life index; the net present value before income taxes of the future net revenue attributable to our reserves; forecast prices for oil and natural gas; forecast inflation and exchange rates; future development costs; the value of our undeveloped land holdings; and our estimated net asset value. 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.

These forward-looking statements are based on certain key assumptions regarding, among other things: petroleum and natural gas prices and differentials between light, medium and heavy oil prices; well production rates and reserve volumes; our ability to add production and reserves through our exploration and development activities; capital expenditure levels; our ability to borrow under our credit agreements; 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; 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). Readers are 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: the volatility of oil and natural gas prices; further declines or an extended period of the currently low oil and natural gas prices; failure to comply with the covenants in our debt agreements; our credit facilities not providing sufficient liquidity; refinancing risk for existing debt and debt service costs; uncertainties in the credit markets may restrict the availability of credit or increase the cost of borrowing; 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; the implementation of strategies for reducing greenhouse gases; variations in interest rates and foreign exchange rates; risks associated with our hedging activities; the cost of developing and operating our assets; risks related to the accessibility, availability, proximity and capacity of gathering, processing and pipeline systems; 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; our inability to fully insure against all risks; risks that our counterparties will default; 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; depletion of our reserves; risks associated with the ownership of our securities, including changes in market-based factors and the discretionary nature of dividend payments; 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, 2015, 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 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 will be the same in whole or in part as those referenced in the forward-looking statements 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 capital investments and future dividends to shareholders. The most directly comparable measures calculated in accordance with GAAP are cash flow from operating activities and net income.

Net debt is not a measurement based on GAAP in Canada. We define net 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. Our determination of operating netback may not be comparable with the calculation of similar measures for other entities. We believe 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, 2015, which will be filed on or before March 30, 2016. 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, 2015 of the volumes of "contingent resources" for our oil resource plays in Peace River and Northeast areas of Alberta and the Sugarkane area in South Texas. 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 an 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 81% of Baytex's production is weighted toward crude oil and natural gas liquids. Baytex's common shares trade 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:

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