BAYTEX

ENERGY CORP.

BAYTEX REPORTS 2017 RESULTS WITH 26% INCREASE IN ADJUSTED FUNDS FLOW, 6% INCREASE IN RESERVES AND STRONG EAGLE FORD PERFORMANCE

CALGARY, ALBERTA (March 6, 2018) - Baytex Energy Corp. ("Baytex")(TSX, NYSE: BTE) reports its operating and financial results for the three months and year ended December 31, 2017 (all amounts are in Canadian dollars unless otherwise noted).

“Our fourth quarter results demonstrate the impressive cash generating capability of our assets as commodity prices improve. With WTI averaging US$55/bbl, we realized our strongest operating netback in three years and generated adjusted funds flow of $106 million, a level we have not seen since mid-2015. We are delivering outstanding drilling results across our portfolio, including some of our best ever new well production rates in the Eagle Ford. In 2017, we continued to drive cost and capital efficiency in our business and I am pleased that we increased our production, reserves and adjusted funds flow. Our plans for 2018 build on this operational momentum,” commented Ed LaFehr, President and Chief Executive Officer.

Highlights

- Generated production of 69,556 boe/d (81% oil and NGL) during Q4/2017, an increase of 7% over Q4/2016, and 70,242 boe/d for full-year 2017, exceeding the high end of guidance, with capital expenditures of $326 million, in line with annual guidance;

- Delivered adjusted funds flow of $106 million ($0.45 per basic share) in Q4/2017, an increase of 37% over Q4/2016, and $348 million ($1.48 per basic share) for the full-year 2017, an increase of 26% over 2016;

- Decreased cash costs (operating, transportation and general and administrative expenses) by 7.5% on a boe basis as compared to the mid-point of original guidance;

- Realized an operating netback in Q4/2017 of $21.78/boe ($22.08/boe including financial derivative gains);

- Reduced net debt to $1.73 billion; adjusted funds flow exceeded capital expenditures by $21 million;

- Continued strong performance in the Eagle Ford with wells that commenced production during Q4/2017 representing some of the highest productivity wells drilled to-date with 30-day initial gross production rates of approximately 1,700 boe/d per well. Two wells in our new northern Austin Chalk fracture trend demonstrated 30-day initial gross production rates of approximately 2,400 boe/d per well (89% liquids);

- Increased proved plus probable reserves by 6% to 432 mmboe (201% production replacement). Year-end 2017 proved plus probable reserves are comprised of 80% oil and NGL and 20% natural gas;

- Recorded finding and development (“F&D”) costs for proved plus probable reserves, including changes in future development costs, of $7.26/boe and generated a recycle ratio of 2.7x. Recorded finding, development and acquisition (“FD&A”) costs of $9.11/boe with a recycle ratio of 2.2x;

- In the Eagle Ford, replaced 225% of production and increased proved plus probable reserves by 8% to 233 mmboe. From the time of acquisition in June 2014, proved plus probable reserves in the Eagle Ford have increased by 40%. Prior to deducting total production of 49 mmboe over this period, reserves growth is approximately 70%;

- In Canada, replaced 175% of production and increased proved plus probable reserves by 5% to 199 mmboe, as we returned to active development, including the integration of the heavy oil assets acquired in the Peace River region in January 2017; and

- Net asset value at year-end 2017 increased 11% to $10.08 per share (before tax and discounted at 10%).

	Three Months Ended			Years Ended	
	December 31, 2017	September 30, 2017	December 31, 2016	**December 31, 2017**	December 31, 2016
FINANCIAL *(thousands of Canadian dollars, except per common share amounts)*					
Petroleum and natural gas sales	**$ 302,186**	$ 254,430	$ 233,116	**$ 1,091,534**	$ 780,095
Adjusted funds flow (1)	**105,796**	77,340	77,239	**347,641**	276,251
Per share – basic	**0.45**	0.33	0.36	**1.48**	1.30
Per share – diluted	**0.44**	0.33	0.36	**1.47**	1.30
Net income (loss)	**76,038**	(9,228)	(359,424)	**87,174**	(485,184)
Per share – basic	**0.32**	(0.04)	(1.66)	**0.37**	(2.29)
Per share – diluted	**0.32**	(0.04)	(1.66)	**0.37**	(2.29)
Exploration and development	**90,156**	61,544	68,029	**326,266**	224,783
Acquisitions, net of divestitures	**(3,937)**	(7,436)	(322)	**59,857**	(63,120)
Total oil and natural gas capital expenditures	**$ 86,219**	$ 54,108	$ 67,707	**$ 386,123**	$ 161,663
Bank loan (2)	**$ 213,376**	$ 226,249	$ 191,286	**$ 213,376**	$ 191,286
Long-term notes (2)	**1,489,210**	1,488,450	1,584,158	**1,489,210**	1,584,158
Long-term debt	**1,702,586**	1,714,699	1,775,444	**1,702,586**	1,775,444
Working capital (surplus) deficiency	**31,698**	34,106	(1,903)	**31,698**	(1,903)
Net debt (3)	**$ 1,734,284**	$ 1,748,805	$ 1,773,541	**$ 1,734,284**	$ 1,773,541

	Three Months Ended			Years Ended	
	December 31, 2017	September 30, 2017	December 31, 2016	**December 31, 2017**	December 31, 2016
OPERATING					
Daily production					
Heavy oil (bbl/d)	**24,945**	26,161	22,982	**25,326**	23,586
Light oil and condensate (bbl/d)	**21,229**	20,041	20,163	**21,314**	21,377
NGL (bbl/d)	**9,872**	8,940	8,319	**9,206**	9,349
Total oil and NGL (bbl/d)	**56,046**	55,142	51,464	**55,846**	54,312
Natural gas (mcf/d)	**81,063**	85,006	82,032	**86,375**	91,182
Oil equivalent (boe/d @ 6:1) (4)	**69,556**	69,310	65,136	**70,242**	69,509
Benchmark prices					
WTI oil (US$/bbl)	**55.40**	48.20	49.29	**50.95**	43.33
WCS heavy oil (US$/bbl)	**43.14**	38.26	34.97	**38.97**	29.49
Edmonton par oil ($/bbl)	**69.02**	56.74	61.58	**62.92**	53.01
LLS oil (US$/bbl)	**60.50**	50.27	49.95	**53.26**	43.82
Baytex average prices (before hedging)					
Heavy oil ($/bbl) (5)	**42.03**	38.18	34.33	**38.46**	26.46
Light oil and condensate ($/bbl)	**72.64**	58.22	60.12	**63.74**	50.32
NGL ($/bbl)	**29.14**	25.18	22.64	**25.86**	17.16
Total oil and NGL ($/bbl)	**51.35**	43.36	42.55	**46.03**	34.25
Natural gas ($/mcf)	**2.89**	2.89	3.61	**3.24**	2.69
Oil equivalent ($/boe)	**44.75**	38.04	38.16	**40.58**	30.29
CAD/USD noon rate at period end	**1.2518**	1.2510	1.3427	**1.2518**	1.3427
CAD/USD average rate for period	**1.2717**	1.2524	1.3339	**1.2979**	1.3256

	Three Months Ended			Years Ended	
	December 31, 2017	September 30, 2017	December 31, 2016	**December 31, 2017**	December 31, 2016
COMMON SHARE INFORMATION					
TSX					
Share price (Cdn$)					
High	**4.59**	4.13	7.35	**6.97**	9.04
Low	**2.95**	2.76	4.85	**2.76**	1.57
Close	**3.77**	3.76	6.56	**3.77**	6.56
Volume traded (thousands)	**195,013**	156,562	351,040	**823,591**	1,677,986
NYSE					
Share price (US$)					
High	**3.06**	3.16	5.61	**5.20**	7.14
Low	**2.30**	2.13	3.60	**2.13**	1.08
Close	**2.76**	3.01	4.48	**2.76**	4.48
Volume traded (thousands)	**25,504**	81,848	186,423	**356,263**	707,973
Common shares outstanding (thousands)	**235,451**	235,451	233,449	**235,451**	233,449

Notes:

(1) Adjusted funds flow 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 adjusted funds flow as cash flow from operating activities adjusted for changes in non-cash operating working capital and asset retirement obligations settled. Our determination of adjusted funds flow may not be comparable to other issuers. We consider adjusted funds flow a key measure of performance as it demonstrates our ability to generate the cash flow necessary to fund capital investments, debt repayment, settlement of our abandonment obligations and potential future dividends. In addition, we use the ratio of net debt to adjusted funds flow to manage our capital structure. We eliminate changes in non-cash working capital and settlements of abandonment obligations from cash flow from operations as the amounts can be discretionary and may vary from period to period depending on our capital programs and the maturity of our operating areas. The settlement of abandonment obligations are managed with our capital budgeting process which considers available adjusted funds flow. For a reconciliation of adjusted funds flow to cash flow from operating activities, see Management's Discussion and Analysis of the operating and financial results for the year ended December 31, 2017.

(2) Principal amount of instruments.

(3) Net debt is not a measurement based on GAAP in Canada, but is a financial term commonly used in the oil and gas industry. We define net debt to be the sum of monetary working capital (which is current assets less current liabilities (excluding current financial derivatives and onerous contracts)) and the principal amount of both the long-term notes and the bank loan.

(4) 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.

(5) Heavy oil prices exclude condensate blending.

Operating Results

2017 was a year about delivering on our commitments in a challenging commodity price environment. We delivered on our operational and financial targets, reduced our overall debt and acquired a strategic asset in Peace River. In addition, we continued to drive cost and capital efficiency in our business and increased our production, reserves and adjusted funds flow.

Production averaged 69,556 boe/d (81% oil and NGL) in Q4/2017, as compared to 69,310 boe/d (80% oil and NGL) in Q3/2017 and 65,136 boe/d in Q4/2016. For the full-year 2017, production averaged 70,242 boe/d (80% oil and NGL), exceeding the high end of our production guidance range of 66,000 to 70,000 boe/d announced in December 2016 and subsequently tightened to 69,500 to 70,000 boe/d.

Capital expenditures for exploration and development activities totaled $90 million in Q4/2017 and $326 million for full-year 2017, in line with our guidance range of $300-$350 million announced in December 2016 and subsequently tightened to $310-$330 million. We participated in the drilling of 226 (86.6 net) wells with a 100% success rate during the year.

We generated adjusted funds flow of $348 million during 2017, exceeding capital expenditures by $21 million. We employ a flexible approach to prudently manage our capital program as we target exploration and development capital expenditures at a level that approximates our adjusted funds flow.

Eagle Ford

Our Eagle Ford asset in South Texas is one of the premier oil resource plays in North America. The assets generate the highest cash netbacks in our portfolio and contain a significant inventory of development prospects. In 2017, we allocated 65% of our exploration and development expenditures to these assets.

Production averaged 37,362 (78% liquids) during the fourth quarter, as compared to 34,750 boe/d in Q3/2017. Production for the full-year 2017 averaged 36,678 boe/d.

We continue to see strong well performance driven by enhanced completions in the oil window of our acreage. In 2017, we participated in the drilling of 140 (32.8 net) wells and commenced production from 115 (28.7 net) wells. The wells that have been on production for more than 30 days during 2017 established 30-day initial production rates of approximately 1,450 boe/d, which represents an approximate 12% improvement over 2016.

During the fourth quarter, we participated in the completion of five pads (total of 25 gross wells), including two in Longhorn and three in Sugarloaf. These pads were completed with approximately 30 effective frac stages per well and proppant per completed foot of approximately 2,000 pounds, which is more than double the frac intensity of wells previously drilled in the area. The wells that commenced production during the fourth quarter represent some of the highest productivity wells drilled to-date on our lands and, on average, established 30-day initial gross production rates of approximately 1,700 boe/d per well. Two of these wells in our new northern Austin Chalk fracture trend demonstrated 30-day initial gross production rates of approximately 2,400 boe/d per well.

Peace River

Our Peace River region, located in northwest Alberta, has been a core asset since we commenced operations in the area in 2004. Through our innovative multi-lateral horizontal drilling and production techniques, we are able to generate some of the strongest capital efficiencies in the oil and gas industry. In addition, through detailed re-mapping of the Bluesky formation, we have been able to effectively increase our exposure to pay in the laterals of new wells, achieving 97% in zone performance.

Production averaged 16,700 boe/d (93% heavy oil) during the fourth quarter and 17,550 boe/d for the full-year 2017. After limited activity on these lands in 2016, we drilled 8 (8.0 net) wells in 2017. These wells established an average 30-day initial production rate of approximately 400 bbl/d per well with our highest productivity well averaging over 600 bbl/d.

Lloydminster

Our Lloydminster region, which straddles the Alberta and Saskatchewan border, is characterized by multiple stacked pay formations at relatively shallow depths, which we have successfully developed through vertical and horizontal drilling, water flood and steam-assisted gravity drainage operations. We have also adopted, where applicable, the multi-lateral well design and geosteering capability that we have successfully utilized at Peace River.

Production averaged 9,600 boe/d (99% heavy oil) during the fourth quarter and 9,100 boe/d for the full-year 2017. We drilled 24 (11.4 net) wells during the fourth quarter and 65 (32.8 net) wells in 2017. During the fourth quarter, seven operated wells (including four multi-lateral horizontal wells) established an average 30-day initial production rate of approximately 180 bbl/d per well.

Financial Review

We generated adjusted funds flow of $106 million ($0.45 per basic share) in Q4/2017, compared to $77 million ($0.33 per basic share) in Q3/2017. Full-year adjusted funds flow was $348 million ($1.48 per basic share), compared to $276 million ($1.30 basic per share) in 2016. Excluding financial derivatives gains, adjusted funds flow in 2017 was $340 million, compared to $179 million in 2016, an increase of 90% due primarily to higher commodity prices. This illustrates the sensitivity of our operations to improvements in commodity prices.

Financial Liquidity

We maintain strong financial liquidity with our US$575 million revolving credit facilities approximately 70% undrawn and our first long-term note maturity not until 2021. With our strategy to target exploration and development capital expenditures at a level that approximates our adjusted funds flow, we expect this liquidity position to be stable going forward.

Our revolving credit facilities, which currently mature in June 2019, are covenant-based and do not require annual or semi-annual reviews. We are well within our financial covenants on these facilities as our Senior Secured Debt to Bank EBITDA ratio as at December 31, 2017 was 0.5:1.0, compared to a maximum permitted ratio of 5.0:1.0 (which steps down to 3.5:1.0 after December 31, 2018) and our interest coverage ratio was 4.5:1.0, compared to a minimum required ratio of 1.25:1.0 (which steps up to 2.0:1.0 after December 31, 2018).

Our net debt totaled $1.73 billion at December 31, 2017, which is down $39 million from December 31, 2016.

Operating Netback

Our fourth quarter operating netback of $21.78/boe (excluding financial derivatives) is the strongest we have realized since 2014 and demonstrates the cash generating ability of our assets in an improved commodity price environment. The Eagle Ford generated an operating netback of $30.19/boe during Q4/2017 while our Canadian operations generated an operating netback of $12.01/boe.

In Q4/2017, the price for West Texas Intermediate light oil ("WTI") averaged US$55.40/bbl, as compared to US$49.29/bbl in Q4/2016. The discount for Canadian heavy oil, as measured by the price differential between Western Canadian Select ("WCS") and WTI, improved slightly during Q4/2017, averaging US$12.26/bbl, as compared to US$14.32/bbl in Q4/2016.

In the Eagle Ford, our assets are proximal to Gulf Coast markets with light oil and condensate production priced off the Louisiana Light Sweet ("LLS") crude oil benchmark, which is a function of the Brent price. As a result, we benefited during the fourth quarter from a widening of the Brent-WTI spread. In addition, increased competition for physical field supplies has resulted in improved price realizations relative to LLS. During the fourth quarter, our light oil and condensate price in the Eagle Ford of US$57.47/bbl (or $73.08/bbl), which represented a US$3.03/bbl discount to LLS, as compared to a historical discount of approximately US$6.00/bbl.

The following table summarizes our operating netbacks for the periods noted.

	Three Months Ended December 31					
	2017			2016		
($ per boe except for sales volume)	**Canada**	**U.S.**	**Total**	**Canada**	**U.S.**	**Total**
Sales volume (boe/d)	**32,194**	**37,362**	**69,556**	31,704	33,432	65,136
Realized sales price	**$ 36.89**	**$ 51.53**	**$ 44.75**	$ 31.10	$ 44.84	$ 38.16
Less:						
Royalties	**5.72**	**15.30**	**10.86**	4.82	13.52	9.28
Operating expense	**16.57**	**6.04**	**10.91**	13.10	6.98	9.96
Transportation expense	**2.59**	**—**	**1.20**	2.67	—	1.30
Operating netback	**$ 12.01**	**$ 30.19**	**$ 21.78**	$ 10.51	$ 24.34	$ 17.62
Realized financial derivatives gain	**—**	**—**	**0.30**	—	—	1.62
Operating netback after financial derivatives gain	**$ 12.01**	**$ 30.19**	**$ 22.08**	$ 10.51	$ 24.34	$ 19.24

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 adjusted funds flow. We realized a financial derivatives gain of $8 million in 2017, as compared to a gain of $97 million in 2016.

For 2018, we have entered into hedges on approximately 54% of our net crude oil exposure. This includes 43% of our net WTI exposure with 38% fixed at US$52.26/bbl and 5% hedged utilizing a 3-way option structure that provides us with downside price protection at US$54.40/bbl and upside participation to US$60.00/bbl. In addition, we have entered into a Brent-based hedge for 4,000 bbl/d at US$61.31/bbl. We have also entered into hedges on approximately 33% of our net WCS differential exposure at a price differential to WTI of US$14.19/bbl and 28% of our net natural gas exposure through a combination of AECO swaps at C$2.82/mcf and NYMEX swaps at US$3.01/mmbtu.

As part of our risk management program, we also transport crude oil to markets by rail when economics warrant. In 2017, we delivered 5,000 bbl/d (approximately 20%) of our heavy oil volumes to market by rail. We expect our oil volumes delivered to market by rail to increase to approximately 6,000-7,000 bbl/d during the first quarter of 2018.

A complete listing of our financial derivative contracts can be found in Note 18 to our 2017 financial statements.

Outlook for 2018

Commodity prices remain volatile with WTI currently above US$60/bbl and Canadian heavy oil differentials averaging US$24/bbl for Q1/2018 due to transportation challenges. We see these wide differentials as temporary as the industry works to alleviate the bottlenecks through crude by rail and existing pipeline optimization and reconfigurations. We remain supporters of pipeline expansion as our medium term solutions to market access. We have the operational flexibility to adjust our spending plans based on changes in the commodity price environment.

We are encouraged by our operating results in the Eagle Ford and the strong cash generating capability of this asset as the prices for Brent and LLS are above US$63/bbl. During the fourth quarter, our netback in the Eagle Ford of $30.19/bbl was the strongest we have realized since 2014. At current crude oil prices, we expect the Eagle Ford to generate significant free cash flow in 2018.

In Canada, we are executing our first quarter drilling and development program as planned with improved WTI pricing partially offsetting the widening of the WCS differential. We continue to manage our heavy oil sales portfolio, including operational optimization, crude-by rail and the use of financial and physical hedges to optimize our heavy oil netbacks.

Our 2018 production guidance range is unchanged at 68,000 to 72,000 boe/d with budgeted exploration and development capital expenditures of $325 to $375 million.

The following table summarizes our 2018 annual guidance.

Exploration and development capital	$325 - $375 million
Production	68,000 - 72,000 boe/d
Expenses:	
Royalty rate	~ 23%
Operating	$10.50 - $11.25/boe
Transportation	$1.35 - $1.45/boe
General and administrative	~$44 million, $1.72/boe
Interest	~ $100 million, $3.95/boe

Year-end 2017 Reserves

Baytex's year-end 2017 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, 2017 forecast price and cost assumptions. Ryder Scott also evaluated the possible reserves associated with our Eagle Ford assets.

All of our 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") and the Canadian Oil and Gas Evaluation Handbook (the "COGE Handbook"). Reserves associated with our thermal heavy oil projects at Peace River, Gemini (Cold Lake) and Kerrobert have been classified as bitumen. Complete reserves disclosure will be included in our Annual Information Form for the year ended December 31, 2017, which will be filed on or before March 31, 2018.

2017 Highlights

Highlights of the evaluation of our Total Proved plus Probable (“2P”), Total Proved (“1P”) and Proved Developed Producing (“PDP”) reserves are provided below. Finding and development (“F&D”) and finding, development and acquisition (“FD&A”) costs are all reported inclusive of future development costs (“FDC”).

- **Active Development in the U.S. and Canada Drives Reserves Growth:** Continued strong performance and capital investment levels in the Eagle Ford along with a resumption of activity in Canada delivered reserves and value growth. Relative to year-end 2016, total company 2P reserves increased 6% to 432 mmboe (201% production replacement) while 1P reserves increased 1% to 256 mmboe (111% production replacement). As a percentage of 2P reserves, oil and NGL reserves represented 80%.

- **Strong Recycle Ratios:** Total company 2P F&D of $7.26/boe and 2P FD&A of $9.11/boe improved relative to our three-year averages of $10.45/boe and $10.51/boe, respectively. Based on our 2017 operating netback of $19.62/boe (including financial derivatives gain), we generated strong recycle ratios of 2.7x for F&D and 2.2x for FD&A in 2017. 1P and PDP F&D recycle ratios improved to 2.2x and 1.4x, respectively.

- **Growth in Value:** The net present value (before income taxes) of the future net revenue attributable to our reserves, discounted at 10%, is estimated to be $4.1 billion ($3.9 billion at year-end 2016). This led to a net asset value[(1)], discounted at 10%, of $10.08 per share (11% higher than year-end 2016). We maintained a strong reserves life index (“RLI”), excluding thermal reserves, of 9.5 years on a proved basis and 14.3 years on a proved plus probable basis, which is calculated using annualized Q4/2017 production.

- **Continued Outperformance in the Eagle Ford:** Eagle Ford 2P reserves increased 8% to 233.3 mmboe, replacing 225% of production. Since acquiring the assets in June 2014, 2P reserves in the Eagle Ford have grown 40%. Positive technical revisions of 20.8 mmboe were realized in the Eagle Ford, reflecting enhanced type well profiles. We have also booked an initial 5.7 mmboe in our new fractured Austin Chalk play in the northern part of our acreage.

- **Resumption of Activity in Canada:** Canada 2P reserves increased 5% to 198.7 mmboe, replacing 175% of production due to a return to active development in Canada, including the integration of the heavy oil assets acquired in the Peace River region in January 2017.

Note:

(1) Based on the estimated reserves value of $4.1 billion plus a value for undeveloped land holdings, net of long-term debt, asset retirement obligations and working capital. See “Net Asset Value”.

The following table reconciles the change in reserves during 2017 by reserves category and operating area.

(gross reserves, mmboe)	Eagle Ford	Heavy Oil	Canada Conventional	Thermal	Total
Proved Developed Producing					
December 31, 2016	60.8	28.3	9.0	0.4	98.5
Additions, net of revisions	16.7	9.6	1.2	0.0	27.5
Production	(13.4)	(9.4)	(2.5)	(0.3)	(25.6)
December 31, 2017	64.1	28.5	7.7	0.1	100.4
% Change	5%	1%	(14%)	—	2%
Proved					
December 31, 2016	168.1	55.2	15.9	13.5	252.7
Additions, net of revisions	17.0	9.0	2.3	0.1	28.5
Production	(13.4)	(9.4)	(2.5)	(0.3)	(25.6)
December 31, 2017	171.7	54.8	15.7	13.3	255.6
% Change	2%	(1%)	(1%)	(1%)	1%
Proved Plus Probable					
December 31, 2016	216.5	85.0	35.3	69.3	406.1
Additions, net of revisions	30.2	20.1	1.2	0.0	51.5
Production	(13.4)	(9.4)	(2.5)	(0.3)	(25.6)
December 31, 2017	233.3	95.7	34.0	69.0	432.0
% Change	8%	13%	(4%)	0%	6%

Petroleum and Natural Gas Reserves as at December 31, 2017

The following table sets forth our gross and net reserves volumes at December 31, 2017 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	26,276	20,748	94	92	1,482	1,441
Developed Non-Producing	1,750	1,498	7,744	7,072	1	1
Undeveloped	18,680	16,608	5,428	4,546	125	122
Total Proved	46,706	38,854	13,266	11,709	1,608	1,564
Probable	39,757	33,563	55,726	43,833	1,225	1,090
Total Proved Plus Probable	86,463	72,417	68,992	55,542	2,833	2,654

CANADA	**Forecast Prices and Costs**					
	Natural Gas Liquids[3]		**Conventional Natural Gas[4]**		**Oil Equivalent[5]**	
Reserves Category	**Gross[1] (mbbl)**	**Net[2] (mbbl)**	**Gross[1] (mmcf)**	**Net[2] (mmcf)**	**Gross[1] (mboe)**	**Net[2] (mboe)**
Proved						
Developed Producing	1,075	761	43,929	37,680	36,249	29,322
Developed Non-Producing	21	12	27,034	25,309	14,021	12,801
Undeveloped	1,522	1,228	46,856	41,080	33,564	29,351
Total Proved	2,618	2,002	117,819	104,069	83,834	71,474
Probable	3,132	2,428	89,963	77,782	114,834	93,878
Total Proved Plus Probable	5,750	4,430	207,782	181,853	198,667	165,352

UNITED STATES	**Forecast Prices and Costs**					
	Tight Oil		**Natural Gas Liquids[3]**		**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	20,191	14,809	28,052	20,742	61,139	45,273
Developed Non-Producing	32	23	111	81	209	152
Undeveloped	30,074	22,022	53,784	39,590	111,506	82,186
Total Proved	50,296	36,854	81,947	60,413	172,855	127,611
Probable	11,390	8,361	35,830	26,333	75,686	55,607
Total Proved Plus Probable	61,686	45,215	117,777	86,745	248,541	183,218
Possible[6]	19,992	14,679	41,964	30,862	89,370	65,736
Total Proved Plus Probable Plus Possible	81,679	59,894	159,741	117,607	337,910	248,954

UNITED STATES	**Forecast Prices and Costs**			
	Conventional Natural Gas[4]		**Oil Equivalent**[5]	
Reserves Category	**Gross**[1] **(mmcf)**	**Net**[2] **(mmcf)**	**Gross**[1] **(mboe)**	**Net**[2] **(mbbl)**
Proved				
Developed Producing	34,115	25,076	64,119	47,276
Developed Non-Producing	91	65	193	140
Undeveloped	29,812	21,794	107,410	78,942
Total Proved	64,018	46,935	171,722	126,358
Probable	10,761	7,900	61,628	45,278
Total Proved Plus Probable	74,778	54,835	233,349	171,635
Possible[6]	19,577	14,372	80,115	58,892
Total Proved Plus Probable Plus Possible	94,356	69,207	313,464	230,528

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	26,276	20,748	94	92	1,482	1,441
Developed Non-Producing	1,750	1,498	7,744	7,072	1	1
Undeveloped	18,680	16,608	5,428	4,546	125	122
Total Proved	46,706	38,854	13,266	11,709	1,608	1,564
Probable	39,757	33,563	55,726	43,833	1,225	1,090
Total Proved Plus Probable	86,463	72,417	68,992	55,542	2,833	2,654
Possible[6][7]	—	—	—	—	—	—
Total Proved Plus Probable Plus Possible	86,463	72,417	68,992	55,542	2,833	2,654

TOTAL	**Forecast Prices and Costs**					
	Tight Oil		**Natural Gas Liquids**[3]		**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	20,191	14,809	29,128	21,503	61,139	45,273
Developed Non-Producing	32	23	131	93	209	152
Undeveloped	30,074	22,022	55,306	40,818	111,506	82,186
Total Proved	50,296	36,854	84,564	62,414	172,855	127,611
Probable	11,390	8,361	38,962	28,760	75,686	55,607
Total Proved Plus Probable	61,686	45,215	123,526	91,175	248,541	183,218
Possible[6][7]	19,992	14,679	41,964	30,862	89,370	65,736
Total Proved Plus Probable Plus Possible	81,679	59,894	165,491	122,037	337,910	248,954

TOTAL	Forecast Prices and Costs			
	Conventional Natural Gas[4]		Oil Equivalent[5]	
Reserves Category	Gross[1] (mmcf)	Net[2] (mmcf)	Gross[1] (mboe)	Net[2] (mboe)
Proved				
Developed Producing	78,045	62,756	100,368	76,598
Developed Non-Producing	27,125	25,374	14,214	12,941
Undeveloped	76,668	62,874	140,974	108,293
Total Proved	181,837	151,004	255,556	197,831
Probable	100,723	85,683	176,461	139,155
Total Proved Plus Probable	282,561	236,687	432,017	336,987
Possible[6][7]	19,577	14,372	80,115	58,892
Total Proved Plus Probable Plus Possible	302,138	251,059	512,131	395,879

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) Natural Gas Liquids includes condensate.

(4) Conventional Natural Gas includes associated, non-associated and solution gas.

(5) 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.

(6) 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.

(7) 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

	Heavy Oil			Bitumen		
Gross Reserves Category	**Proved (mbbl)**	**Probable (mbbl)**	**Proved + Probable (mbbl)**	**Proved (mbbl)**	**Probable (mbbl)**	**Proved + Probable (mbbl)**
December 31, 2016	46,875	29,325	76,199	13,465	55,835	69,300
Extensions	638	500	1,138	—	—	—
Infill Drilling	369	364	732	—	—	—
Improved Recoveries	—	1,997	1,997	—	—	—
Technical Revisions	1,121	(2,861)	(1,740)	197	(142)	55
Discoveries	—	—	—	—	—	—
Acquisitions [3]	7,941	11,334	19,275	—	—	—
Dispositions	(1,221)	(974)	(2,195)	—	—	—
Economic Factors	(89)	73	(16)	(80)	33	(47)
Production	(8,927)	—	(8,927)	(317)	—	(317)
December 31, 2017	46,706	39,757	86,463	13,266	55,726	68,992

	Light and Medium Crude Oil			Tight Oil		
Gross Reserves Category	**Proved (mbbl)**	**Probable (mbbl)**	**Proved + Probable (mbbl)**	**Proved (mbbl)**	**Probable (mbbl)**	**Proved + Probable (mbbl)**
December 31, 2016	2,293	1,794	4,087	49,714	8,399	58,113
Extensions	—	—	—	—	—	—
Infill Drilling	—	—	—	1,307	2,252	3,559
Improved Recoveries	—	—	—	—	—	—
Technical Revisions [4]	422	31	453	3,821	736	4,557
Discoveries	—	—	—	—	—	—
Acquisitions	—	—	—	—	—	—
Dispositions	(720)	(559)	(1,279)	—	—	—
Economic Factors	38	(41)	(3)	8	3	11
Production	(425)	—	(425)	(4,553)	—	(4,553)
December 31, 2017	1,608	1,225	2,833	50,296	11,390	61,686

	Natural Gas Liquids[5]			Shale Gas		
Gross Reserves Category	**Proved (mbbl)**	**Probable (mbbl)**	**Proved + Probable (mbbl)**	**Proved (mmcf)**	**Probable (mmcf)**	**Proved + Probable (mmcf)**
December 31, 2016	82,692	31,825	114,516	173,828	59,075	232,903
Extensions	90	224	314	—	—	—
Infill Drilling	1,393	1,095	2,488	2,096	6,464	8,560
Improved Recoveries	—	—	—	—	—	—
Technical Revisions [4]	6,487	5,758	12,245	7,590	10,190	17,781
Discoveries	—	—	—	—	—	—
Acquisitions	115	81	196	—	—	—
Dispositions	—	—	—	—	—	—
Economic Factors	(50)	(21)	(71)	(133)	(43)	(177)
Production	(6,162)	—	(6,162)	(10,526)	—	(10,526)
December 31, 2017	84,564	38,962	123,526	172,855	75,686	248,541

Gross Reserves Category	Conventional Natural Gas[6] Proved (mmcf)	Conventional Natural Gas[6] Probable (mmcf)	Conventional Natural Gas[6] Proved + Probable (mmcf)	Oil Equivalent[7] Proved (mboe)	Oil Equivalent[7] Probable (mboe)	Oil Equivalent[7] Proved + Probable (mboe)
December 31, 2016	172,016	98,112	270,127	252,679	153,375	406,053
Extensions	2,067	5,042	7,109	1,073	1,564	2,637
Infill Drilling	3,421	845	4,266	3,987	4,929	8,916
Improved Recoveries	—	—	—	—	1,997	1,997
Technical Revisions [4]	21,703	(6,086)	15,617	16,931	4,206	21,137
Discoveries	—	—	—	—	—	—
Acquisitions [3]	4,241	3,008	7,249	8,763	11,916	20,679
Dispositions	(2)	(2)	(4)	(1,942)	(1,534)	(3,475)
Economic Factors	(608)	(195)	(803)	(296)	8	(289)
Production	(21,001)	—	(21,001)	(25,639)	—	(25,639)
December 31, 2017	181,837	100,724	282,560	255,556	176,461	432,017

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, 2017 and 2016 is prepared in accordance with NI 51-101.

(3) Heavy oil and conventional natural gas acquisitions are principally attributable to reserves associated with the Peace River assets acquired on January 20, 2017.

(4) Positive technical revisions for tight oil, natural gas liquids and shale gas are largely the result of enhanced type well profiles on our Eagle Ford acreage.

(5) Natural gas liquids include condensate.

(6) Conventional natural gas includes associated, non-associated and solution gas.

(7) 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 (excluding thermal reserves) at year-end 2017 by annualized Q4/2017 production.

	Q4/2017 Actual Production	Reserves Life Index (years) Proved	Reserves Life Index (years) Proved Plus Probable
Oil and NGL (bbl/d)	56,046	9.0	13.4
Natural Gas (mcf/d)	81,063	12.0	17.9
Oil Equivalent (boe/d)	69,556	9.5	14.3

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.

	2017	2016	2015	Three-Year Total / Average 2015 - 2017
Capital Expenditures ($ millions)				
Exploration and development	$ 326.3	$ 224.8	$ 521.0	$ 1,072.1
Acquisitions (net of dispositions)	59.9	(63.6)	1.6	(2.1)
Total	$ 386.1	$ 161.2	$ 522.7	$ 1,070.0
Change in Future Development Costs – Proved ($ millions)				
Exploration and development	$ (132.6)	$ (219.4)	$ (397.9)	$ (749.9)
Acquisitions (net of dispositions)	35.5	7.6	6.0	49.1
Total	$ (97.1)	$ (211.8)	$ (391.9)	$ (700.8)
Change in Future Development Costs – Proved plus Probable ($ millions)				
Exploration and Development	$ (76.4)	$ 108.8	$ (399.9)	$ (367.5)
Acquisitions (net of dispositions)	160.6	1.9	0.5	163.0
Total	$ 84.2	$ 110.7	$ (399.4)	$ (204.5)
Proved Reserves Additions (mboe)				
Exploration and development	21,695	5,041	21,729	48,465
Acquisitions (net of dispositions)	6,821	(1,564)	537	5,794
Total	28,516	3,477	22,266	54,259
Proved plus Probable Reserves Additions (mboe)				
Exploration and development	34,398	17,253	15,782	67,433
Acquisitions (net of dispositions)	17,204	(2,408)	126	14,922
Total	51,602	14,845	15,908	82,355
F&D costs ($/boe) (1)				
Proved	$ 8.93	$ 1.07	$ 5.67	$ 6.65
Proved plus probable	$ 7.26	$ 19.33	$ 7.68	$ 10.45
FD&A costs ($/boe) (2)				
Proved	$ 10.13	$ — (5)	$ 5.88	$ 6.80
Proved plus probable	$ 9.11	$ 18.33	$ 7.75	$ 10.51
Ratios (based on proved plus probable reserves)				
Production replacement ratio (3)	201%	58%	52%	100%
Recycle ratio (4)	2.7x	0.9x	2.9x	2.2x

Notes:

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

(2) FD&A costs are calculated as total capital expenditures (including acquisition and divestitures and the change in FDC) 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). Operating netback is calculated as revenue (including realized financial derivatives gains and losses) less royalties, operating expenses and transportation expenses.

(5) 2016 FD&A costs (proved) were negative due to the reduction in estimated Future Development Costs.

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, 2017
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	$ 394,678	$ 392,339	$ 359,063	$ 327,713	$ 300,965
Developed Non-Producing	322,386	195,869	135,648	98,310	73,393
Undeveloped	475,480	362,040	278,773	216,443	168,923
Total Proved	1,192,544	950,248	773,484	642,465	543,281
Probable	2,428,609	1,326,481	806,284	526,528	360,482
Total Proved Plus Probable	$ 3,621,153	$ 2,276,730	$ 1,579,768	$ 1,168,994	$ 903,763

UNITED STATES

Reserves Category	0% ($000s)	5% ($000s)	10% ($000s)	15% ($000s)	20% ($000s)
Proved					
Developed Producing	$ 1,771,167	$ 1,311,579	$ 1,045,543	$ 875,040	$ 757,316
Developed Non-Producing	4,334	3,227	2,537	2,080	1,763
Undeveloped	2,492,733	1,523,326	1,009,941	705,898	510,856
Total Proved	4,268,233	2,838,131	2,058,020	1,583,018	1,269,934
Probable	1,679,658	812,362	452,804	276,144	178,484
Total Proved Plus Probable	5,947,892	3,650,494	2,510,824	1,859,162	1,448,419
Possible (1)	2,750,546	1,581,035	1,046,186	752,174	570,766
Total Proved Plus Probable Plus Possible (1)	$ 8,698,438	$ 5,231,529	$ 3,557,009	$ 2,611,337	$ 2,019,185

TOTAL

Reserves Category	0% ($000s)	5% ($000s)	10% ($000s)	15% ($000s)	20% ($000s)
Proved					
Developed Producing	$ 2,165,845	$ 1,703,918	$ 1,404,606	$ 1,202,752	$ 1,058,281
Developed Non-Producing	326,719	199,096	138,185	100,390	75,156
Undeveloped	2,968,213	1,885,366	1,288,713	922,341	679,779
Total Proved	5,460,777	3,788,380	2,831,504	2,225,483	1,813,216
Probable	4,108,268	2,138,844	1,259,087	802,673	538,966
Total Proved Plus Probable	9,569,045	5,927,224	4,090,592	3,028,156	2,352,182
Possible (1)(2)	2,750,546	1,581,035	1,046,186	752,174	570,766
Total Proved Plus Probable Plus Possible (1)(2)	$ 12,319,591	$ 7,508,259	$ 5,136,777	$ 3,780,330	$ 2,922,948

Notes:

(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.

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, 2017.

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
2017 act.	50.95	61.84	48.78	3.02	2.20	2.2	(3.4)	0.771
2018	55.00	65.44	51.05	3.25	2.85	0.0	0.0	0.790
2019	65.00	74.51	59.61	3.50	3.11	2.0	2.0	0.820
2020	70.00	78.24	64.94	4.00	3.65	2.0	2.0	0.850
2021	73.00	82.45	68.43	4.08	3.80	2.0	2.0	0.850
2022	74.46	84.10	69.80	4.16	3.95	2.0	2.0	0.850
2023	75.95	85.78	71.20	4.24	4.05	2.0	2.0	0.850
2024	77.47	87.49	72.62	4.33	4.15	2.0	2.0	0.850
2025	79.02	89.24	74.07	4.42	4.25	2.0	2.0	0.850
2026	80.60	91.03	75.55	4.50	4.36	2.0	2.0	0.850
2027	82.21	92.85	77.06	4.59	4.46	2.0	2.0	0.850
2028	83.86	94.71	78.61	4.69	4.57	2.0	2.0	0.850
Thereafter	Escalation rate of 2.0%							

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.

Future Development Costs
As of December 31, 2017
Forecast Prices and Costs
($000s)

	CANADA		UNITED STATES		TOTAL	
	Proved Reserves	Proved plus Probable Reserves	Proved Reserves	Proved plus Probable Reserves	Proved Reserves	Proved plus Probable Reserves
2018	98,043	126,225	136,837	149,937	234,879	276,163
2019	155,071	188,546	311,259	315,979	466,330	504,524
2020	133,323	357,593	302,301	316,986	435,624	674,579
2021	6,348	263,674	232,243	297,916	238,591	561,590
2022	12,401	122,321	146,451	249,786	158,852	372,107
Remaining	1,734	309,933	141,785	471,862	143,519	781,794
Total (undiscounted)	406,921	1,368,291	1,270,875	1,802,465	1,677,796	3,170,757

Properties with No Attributed Reserves

The following table sets forth our undeveloped land holdings as at December 31, 2017.

	Undeveloped Acres	
	Gross	Net
Canada		
Alberta	748,920	688,166
Saskatchewan	111,360	105,901
Total Canada	860,280	794,067
United States		
Texas	117	102
Total Company	860,397	794,169

Undeveloped land holdings are lands that have not been assigned reserves as at December 31, 2017. We estimate the value of our net undeveloped land holdings at December 31, 2017 to be approximately $75.9 million, as compared to $67.1 million as at December 31, 2016. 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 properties in the vicinity of our undeveloped land holdings, less an allowance for near-term expiries, net of undeveloped acreage that has reserves value attributed.

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 income taxes, as estimated by the Company's independent reserves engineers, Sproule and Ryder Scott, at year-end, plus the estimated value of our undeveloped land holdings, 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 may result in an increase in booked proved plus probable reserves.

The following table sets forth our net asset value as at December 31, 2017.

	Net Asset Value Forecast Prices and Costs Before Income Taxes and Discounted at (%/year)		
($ millions except per share amounts)	**5%**	**10%**	**15%**
Total net present value of proved plus probable reserves (before tax)	$ 5,927	$ 4,091	$ 3,028
Undeveloped land holdings (1)	76	76	76
Asset retirement obligations (2)	(122)	(59)	(42)
Net debt	(1,734)	(1,734)	(1,734)
Net Asset Value	$ 4,147	$ 2,374	$ 1,328
Net Asset Value per Share (3)	$ 17.61	$ 10.08	$ 5.64

Notes:

(1) The value of undeveloped land holdings 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 235.5 million common shares outstanding as at December 31, 2017.

Contingent Resources Assessment

We commissioned Sproule to conduct an evaluation of our contingent resources in the Lloydminster, Peace River, North East Alberta and Pembina areas in Canada. We commissioned Ryder Scott to audit our internal evaluation of our contingent resources in the Eagle Ford area of Texas. Both assessments were effective December 31, 2017, and were prepared in accordance with the Canadian definitions, standards and procedures contained in the COGE Handbook and NI 51-101.

Contingent resources represent the quantity of oil 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. There is no certainty that it will be commercially viable to produce any portion of our contingent resources or that we will produce any portion of the volumes currently classified as contingent resources. The recovery and resource estimates provided 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.

The contingent resources described below represent our gross interests (unless otherwise indicated) 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 summarizes the status of our development pending contingent resources.

Development Pending - Project Status

Area	Product Type	Project Status	Future Development Costs ($ millions)[1]	Timing of First Commercial Production	Recovery Technology
Peace River	Bitumen	Pre-Development	$127	2019-2021	Cyclic steam stimulation ("CSS")
Peace River, Lloydminster and North East Alberta	Heavy Oil	Pre-Development	$227	2018-2023	Horizontal, vertical and multilateral well and polymer flood development
Pembina	Light & Medium Oil, Natural Gas	Pre-Development	$5	2022	Horizontal well development with multi-stage fracturing completion
Eagle Ford	Tight Oil, Shale Gas and NGL	Pre-Development	$128	2018-2028	Horizontal well development with multi-stage fracturing completion

Note:

(1) Undiscounted and unrisked.

The following table presents a summary of the quantitative risk of the chance of development we have applied to our development pending contingent resources.

Development Pending - Chance of Development Risk [1]

Area	Product Type	Unrisked (MMboe)	Chance of Development	Risked (MMboe)	Risked NPV [2] Discounted at 10% (before tax) ($ millions)
Peace River	Bitumen	19	81%	16	86
Peace River, Lloydminster and North East Alberta	Heavy Oil	15	88%	13	46
Pembina	Light & Medium Oil and Natural Gas	1	90%	1	4
Eagle Ford	Tight Oil, Shale Gas and NGL	14	80%	11	100
Total		49		41	236

Notes:

(1) Numbers may not add due to rounding.
(2) An estimate of risked net present value of future net revenue of contingent resources is preliminary in nature and is provided to assist the reader in reaching an opinion on the merit and likelihood of the company 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 no certainty that the estimate of risked net present value of future net revenue will be realized.

The principal risks that would influence the development of the Lloydminster, North East Alberta, Peace River and Pembina 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 of 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 capital commitment and development timing; 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 a summary of the quantitative risk of the chance of development we have applied to our development unclarified contingent resources.

Development Unclarified - Chance of Development Risk [(1)]

Area	Product Type	Unrisked (MMboe)	Chance of Development	Risked (MMboe)
Peace River and North East Alberta	Bitumen	944	58%	552
Peace River, Lloydminster and North East Alberta	Heavy Oil	32	57%	18
Pembina	Light & Medium Oil and Natural Gas	12	55%	7
Eagle Ford	Tight Oil, Shale Gas and NGL	135	50%	67
Total		1,123		644

Note:

(1) Numbers may not add due to rounding.

In addition to the risks identified for the development pending sub-class, the projects in the Lloydminster, North East Alberta, Peace River and Pembina areas 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 CSS and steam-assisted gravity drainage thermal 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, 2017, which will be filed on or before March 31, 2018.

Additional Information

Our audited consolidated financial statements for the year ended December 31, 2017 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 6, 2018, starting at 9:00am MST (11:00am EST). To participate, please dial toll free in North America 1-800-319-4610 or international 1-416-915-3239. Alternatively, to listen to the conference call online, please enter http://services.choruscall.ca/links/baytex20180306.html in your web browser.

An archived recording of the conference call will be available shortly after the event by accessing the webcast link above. 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 2018 plan to build on operational momentum; our strategy to target capital expenditures at a level that approximates our adjusted funds flow; our Eagle Ford assets, including our assessment that: it is a premier oil resource play, generates our highest cash netbacks and has a significant development inventory; that we can generate some of the strongest capital efficiencies in the oil and gas industry at our Peace River assets; the sensitivity of our operations to improvements in commodity prices; that we expect our liquidity position to be stable; our ability to partially reduce the volatility in our adjusted funds flow by utilizing financial derivative contracts for commodity prices, foreign exchange rates and interest rates; the volume of oil that we expect to deliver to market by railways in Q1/2018; that we view the current price differential between WTI and Canadian heavy oil as temporary; that we have operational flexibility to adjust our spending plans based on commodity prices; that we expect the Eagle Ford assets to generate significant free cash flow in 2018; our 2018 production and capital expenditure guidance; our expected royalty rate and operating, transportation, general and administration and interest expenses for 2018; our reserves life index; the net present value before income taxes of the future net revenue attributable to our reserves; forecast prices for petroleum and natural gas; forecast inflation and exchange rates; future development costs; the value of our undeveloped land holdings; our estimated net asset value; that we expect to convert possible reserves and contingent resources to reserves; our development pending contingent resources, including future development costs, timing of first commercial production, risked and unrisked volumes, chance of development and the net present value before income taxes of the future net revenue; and our development unclarified contingent resources, including risked and unrisked volumes and chance of development. In addition, information and statements relating to reserves and contingent resources are deemed to be forward-looking statements, as they involve implied assessment, based on certain estimates and assumptions, that the reserves and contingent resources described exist in quantities predicted or estimated, and that they 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 and price differentials; the availability and cost of capital or borrowing; that our credit facilities may not provide sufficient liquidity or may not be renewed; failure to comply with the covenants in our debt agreements; risks associated with a third-party operating our Eagle Ford properties; availability and cost of gathering, processing and pipeline systems; public perception and its influence on the regulatory regime; changes in government regulations that affect the oil and gas industry; changes in environmental, health and safety regulations; restrictions or costs imposed by climate change initiatives; variations in interest rates and foreign exchange rates; risks associated with our hedging activities; the cost of developing and operating our assets; depletion of our reserves; 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 oil and natural gas reserves; our inability to fully insure against all risks; risks of counterparty default; risks associated with acquiring, developing and exploring for oil and natural gas and other aspects of our operations; risks associated with large projects; risks related to our thermal heavy oil projects; risks associated with our use of information technology systems; risks associated with the ownership of our securities, including 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, 2017, to be filed with Canadian securities regulatory authorities and the U.S. Securities and Exchange Commission not later than March 31, 2018 and in our other public filings.

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 and Capital Management Measures

Adjusted funds flow 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 adjusted funds flow as cash flow from operating activities adjusted for changes in non-cash operating working capital and asset retirement obligations settled. Our determination of adjusted funds flow may not be comparable to other issuers. We consider adjusted funds flow a key measure of performance as it demonstrates our ability to generate the cash flow necessary to fund capital investments, debt repayment, settlement of our abandonment obligations and potential future dividends. In addition, we use the ratio of net debt to adjusted funds flow to manage our capital structure. We eliminate changes in non-cash working capital and settlements of abandonment obligations from cash flow from operations as the amounts can be discretionary and may vary from period to period depending on our capital programs and the maturity of our operating areas. The settlement of abandonment obligations are managed with our capital budgeting process which considers available adjusted funds flow. For a reconciliation of adjusted funds flow to cash flow from operating activities, see Management's Discussion and Analysis of the operating and financial results for the year ended December 31, 2017.

Net debt is not a measurement based on GAAP in Canada. We define net debt to be the sum of monetary working capital (which is current assets less current liabilities (excluding current financial derivatives and onerous contracts)) and the principal amount of both the long-term notes and the 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 the credit agreement governing our revolving credit facilities. Bank EBITDA 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 petroleum and natural gas sales less blending expense, royalties, production and operating expense and transportation expense divided 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, 2017, which will be filed on or before March 31, 2018. 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 metrics commonly used in the oil and natural gas industry, such as “recycle ratio,” “operating netback,” and “reserves life index.” These terms do not have a standardized meaning and may not be comparable to similar measures presented by other companies, and therefore should not be used to make such comparisons. Such metrics have been included in this press release to provide readers with additional measures to evaluate Baytex’s performance, however, such measures are not reliable indicators of Baytex’s future performance and future performance may not compare to Baytex’s performance in previous periods and therefore such metrics should not be unduly relied upon.

This press release contains estimates as of December 31, 2017 of the volumes of "contingent resources" attributable to our properties. These estimates were prepared by independent qualified reserves evaluators.

"Contingent resources" are not, and should not be confused with, petroleum and natural gas reserves. "Contingent resources" are 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 resources the estimated discovered recoverable quantities associated with a project in the early evaluation stage."

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 80% 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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